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Wright Area Coal Leasing Tenth Circuit Court Remand

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Contents

Acronyms

AEO	Annual Energy Outlook
BNSF	Burlington Northern Santa Fe
BTU	British Thermal Unit
CH4	Methane
CO2	Carbon Dioxide
CO2e	Carbon Dioxide Equivalents
CPI	Consumer Price Index
EA	Environmental Assessment
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FCLAA	Federal Coal Leasing Act Amendment
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
FLPMA	Federal Land Policy Management Act
FOB	Free-on-Board/Freight-on-Board
GAO	Government Accountability Office
GHG	Greenhouse Gas
GWP	Global Warming Potential
HPDO	High Plains District Office
IOU	Investor-owned utility
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producers
IRP	Integrated Resource Plan
LBA	Lease-by-Application
MLA	Mineral Leasing Act
MMmt	Million Metric Tonnes
MMmt/yr	Million Metric Tonnes per year
N2O	Nitrous Oxide
NERC	North American Electric Reliability Corporation
NEMS	National Energy Modeling System
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NOA	Notice of Availability
NOI	Notice of Intent
OSMRE	Office of Surface Mining Reclamation and Enforcement
PRB	Powder River Basin
RCT	Regional Coal Team
RMP	Resource Management Plan
ROD	Record of Decision
RTO	Regional Transmission Operators
SMCRA	Surface Mining Control and Reclamation Act
UP	Union Pacific
USGS	U.S. Geological Survey
WDEQ	Wyoming Department of Environmental Quality

Chapter 1

1.1 Introduction

Title: Wright Area Coal Leasing Tenth Circuit Court Remand Environmental Assessment

Environmental Assessment (EA) Number: DOI-BLM-WY-P000-2018-0002-EA

Preparing Office: U.S. Department of the Interior (DOI)
Bureau of Land Management (BLM)
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1.2 Background

BLM has prepared this Remand EA to address a decision of the United States Tenth Circuit Court of Appeals on September 15, 2017, Case No. 15-7609, remanding the Wright Area Final Environmental Impact Statement (FEIS) and coal leasing decisions and the United States District Court's November 27, 2017 order which required BLM to revise a small portion of the Wright Area FEIS environmental analysis. The Tenth Circuit Court did not vacate the Wright Area leases nor the Records of Decision (RODs), but rather, remanded the case to the District Court, which in turn ordered BLM to revise its analysis of the Wright Area FEIS where BLM previously indicated that "there was no real world difference between issuing the Wright Area leases and declining to issue them" given the supply of other available coal. This assumption was included in only the Wright Area FEIS No Action Alternative.

BLM issued four RODs based on the Wright Area FEIS (see Table 1.1.1). In 2012, BLM issued and executed three of the Wright Area federal coal leases, as indicated below. The sale for the North Hilight Field has not yet been held.

Table 1.1.1: Wright Area FEIS Records of Decision (RODs)

Lease #	Lease Name	ROD signed	Mineable Federal coal reserves tonnage	Bonus Bid Revenues Paid to Federal Government	Approved WDEQ* permit for mine that purchased the new lease
WYW174596	South Hilight Field	3-1-2011	222,676,000	$300,001,011	Black Thunder 2014
WYW176095	South Porcupine	8-10-2011	401,830,508	$446,031,863	North Antelope/ Rochelle 2013
WYW173408	North Porcupine	10-17-2011	721,154,828	$793,270,310	North Antelope/ Rochelle 2013
WYW164812	North Hilight Field	2-1-2012	467,596,000	To be determined	To be determined

*Wyoming Department of Environmental Quality

In total, these four Wright Area coal lease tracts in the Wyoming portion of the Powder River Basin (PRB) include over 1.8 billion tons of mineable Federal coal reserves. The coal companies paid the Federal government over $1.5 billion in bonus bid revenues for three of the four lease tracts: the South Hilight Field, South Porcupine, and North Porcupine coal leases[1]. Under the Mineral Leasing Act, 49 percent of the bonus bid revenues was then disbursed back to the State of Wyoming. The federal government received record-setting bids for the Wright Area coal tracts. These three leases were all approved for mining in 2013 and 2014 by the WDEQ and mining is underway and ongoing at all three.

The Wright Area coal tracts were applied for as a direct result of anticipated national coal demand and market demand for affordable electricity. Given the amount of time it could take the BLM to process coal lease applications, coal companies in the PRB have tended to submit coal lease applications well before they anticipate potentially mining new coal tracts. The four tracts of interest are maintenance tracts, meaning that the coal lease would extend the life of the existing mines. These four maintenance tracts are not projected to increase the currently permitted mine production capacity as authorized by WDEQ. When a tract is leased as a maintenance tract, the permit to conduct mining operations for the adjacent mine is amended to include the new lease area prior to surface disturbance. This process can take several years to complete and so, in Wyoming, coal companies often apply for federal coal reserves approximately 10 years in advance of mining. This also allows time for designing logical mining progression.

For example, the graph below shows cumulative Federal coal tons leased in the Wyoming portion of the Powder River Basin (WY PRB) versus cumulative coal tons produced in the WY PRB (both federal and non-federal) (Graph 1.1.1). As shown, federal coal leasing in the WY PRB has been consistent with coal production over time.

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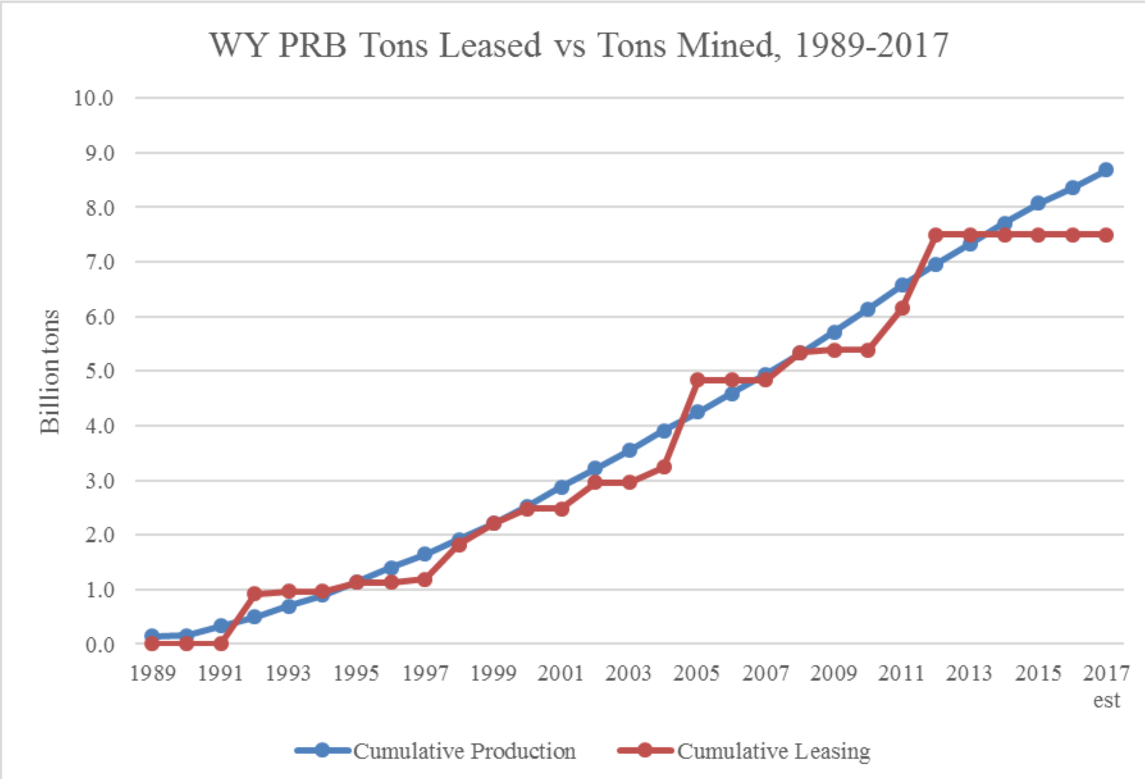
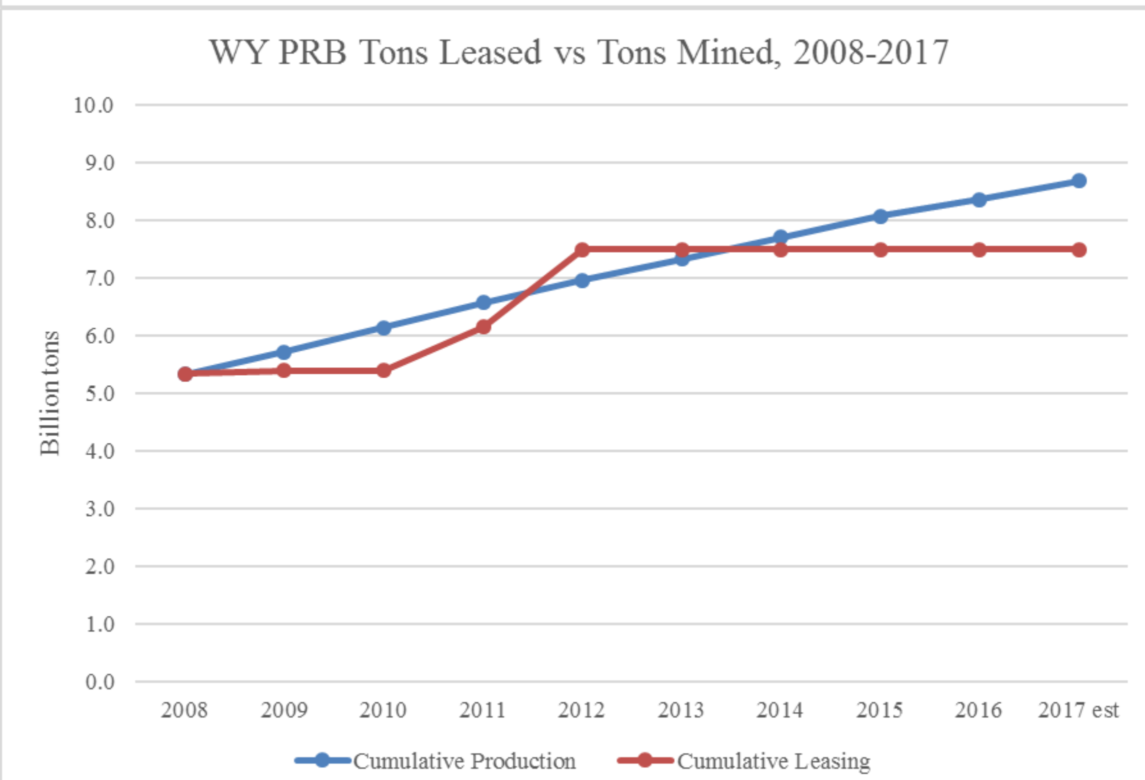
[1] The RODs for these three leases were signed in 2011, the sales of these three leases occurred in 2011 and 2012, and the three leases were issued in 2012.

Graph 1.1.1: Cumulative Federal Coal Tons Leased vs Cumulative Coal Tons Produced





Source: U.S. BLM High Plains District Office 2018

1.3 Purpose and Need of Remand EA

1.3.1 Purpose

As previously described, on September 15, 2017, the Tenth Circuit remanded the Wright Area FEIS and RODs to the District Court. On November 27, 2017 the District Court ordered that the FEIS and RODs be remanded to the BLM for revision on the narrow aspect associated with BLM's analysis that there was no real world difference between issuing the Wright area leases and declining to issue them given the supply of other available coal.

The Tenth Circuit Court of Appeals determined that:

- The Wright Area decisions lacked record support for BLM's conclusion that "it is not likely that selection of the No Action Alternative would result in a decrease of U.S. CO_2 emissions attributable to coal mining and coal-burning power plants in the longer term, because there are multiple other sources of coal that . . . could supply the demand for coal . . ." (page 8-9).

- "BLM concluded that, because overall demand for coal was predicted to increase, the effect on the supply of coal of the No Action Alternative would have no consequential impact on that demand. This long logical leap presumes that either the reduced supply will have no impact on price, or that any increase in price will not make other forms of energy more attractive and decrease coal's share of the energy mix, even slightly" (page 9).

- "The BLM did not point to any information indicating that the national coal deficit of 230 million tons per year incurred under the No Action Alternative could be easily filled from elsewhere, or at a comparable price. It did not refer to the nation's stores of coal or the rates at which those stores may be extracted. Nor did the BLM analyze the specific difference in price between PRB coal and other sources . . ." (page 20).

- "BLM argues, overall increased demand for electricity will override the effect of increased coal prices. But there is no evidence in the record that BLM considered the potential impact of increased price on demand but rather BLM merely concluded it would have no impact. The record contains only BLM's conclusions that the effect on demand would be 'inconsequential,' with no reference to how, or if, it decided which demand-driving factors would prevail or why" (page 22-23).

- " . . . BLM's carbon emissions analysis seems to be liberal (i.e., underestimates the effect on climate change). The RODs assume that coal will continue to be a much used source of fuel for electricity and that coal use will increase with population size" (page 26).

1.3.2 Need

Therefore, consistent with the District Court's November 27, 2017 order, BLM has prepared this environmental assessment (EA) to revise the analysis of the Wright Area FEIS No Action Alternative and further clarify changes in coal supply and demand and associated national carbon dioxide emissions that may have taken place if BLM had rejected the Wright Area lease-by-application (LBA) coal tracts (the Wright Area FEIS No Action Alternative). This Remand EA's additional analysis refines and revises the Wright Area FEIS and RODs, and fulfills both the District Court's November 27, 2017 order and the Tenth Circuit decision.

1.3.3 Discussion

Throughout the Remand EA, BLM's analysis recognizes and acknowledges the following:

- the Wright Area FEIS and RODs, to which this Remand EA is tiered, are incorporated throughout this additional analysis by reference;
- the Wright Area FEIS No Action Alternative is the environmentally preferable alternative; and,
- if the Wright Area FEIS No Action Alternative had been selected, greenhouse gas emissions from the Wright Area LBA coal tracts could have been zero because BLM would have rejected the tracts and the Wright Area LBA coal tracts would not have been permitted for mining at that time. However, the tracts could again be proposed for leasing at some point in the future.

This EA document was chosen as the vehicle to meet the court orders, in part, because it accorded additional opportunity for the public to provide further comment to the BLM. All comments have been considered in the preparation of this Remand EA and are included in the Wright Area's administrative record.

1.3.4 Decision to be Made

The decision to be made is whether the additional documentation and analysis of effects, in this Remand EA of the Wright Area FEIS No Action Alternative, and of the related coal supply and demand and carbon dioxide emissions, adequately support the BLM's decision to approve the subject LBAs or whether the additional documentation and analysis reflects a level of significance not already studied and disclosed in the Wright Area FEIS and RODs.

1.4 Relationship to Statutes, Regulations, Plans, and Other Environmental Analyses

The development of federal coal reserves is integral to the BLM Federal Coal Leasing Program under the authority of the Mineral Leasing Act of 1920 (MLA), as well as the Federal Land Policy Management Act of 1976 (FLPMA) and the Federal Coal Leasing Act Amendments of 1976 (FCLAA). BLM is the lead agency responsible for leasing federal coal lands under the MLA as amended by FCLAA.

After a coal lease is issued, Surface Mining Control and Reclamation Act of 1977 (SMCRA) gives the United States Department of the Interior Office of Surface Mining Reclamation and Enforcement (OSMRE) the primary responsibility to administer programs that regulate surface coal mining operations and the surface effects of underground coal mining operations. Pursuant to Section 503 of SMCRA, the Wyoming Department of Environmental Quality (WDEQ) developed, and in November 1980 the Secretary of the Interior approved, a permanent program authorizing WDEQ to regulate surface coal mining operations and surface effects of underground mining on non-federal lands within the State of Wyoming. In January 1987, pursuant to Section 523(c) of SMCRA, WDEQ entered into a cooperative agreement with the

Secretary of the Interior authorizing WDEQ to regulate surface coal mining operations and surface effects of underground mining on federal lands within the state. Pursuant to this agreement, federal coal lease holders in Wyoming must submit permit application packages to OSMRE and WDEQ for proposed mining and reclamation operations on federal lands in the state.

Land Use Plan Conformance:

FCLAA requires that lands considered for coal leasing be included in a comprehensive land use plan and that leasing decisions be compatible with that plan. The BLM Approved Resource Management Plan (RMP) for Public Lands Administered by the Bureau of Land Management Buffalo Field Office (2001) governed and addressed the leasing of federal coal in Campbell County. The Wright Area coal tracts were all located within the Coal Development Potential Area, as identified and described in the Buffalo RMP.

Other Environmental Analyses and Prior Legal Challenges:

The Powder River Basin (PRB) Coal Review was a regional technical study completed by the BLM to help evaluate the cumulative impacts of coal and other mineral development in the PRB. Initiated in 2003, Phase I of the PRB Coal Review included the identification of current conditions (Task 1 reports); identification of Reasonable Foreseeable Development (RFD) and future coal production scenarios for 2010, 2015, and 2020 (Task 2 reports); and predicted future cumulative impacts (Task 3 reports) in the PRB. Phase II of the PRB Coal Review updated the Phase I analyses, developed future coal production scenarios, and projected cumulative impacts for 2020 and 2030.

The PRB Coal Review provides data, models, and projections to facilitate cumulative analyses for BLM's future land use planning efforts and for future project-specific impact assessments for project development in compliance with the National Environmental Policy Act (NEPA). It should be noted that the PRB Coal Review itself is not a NEPA document. The Powder River Basin Coal Review and related documents are accessible at the following link: https://eplanning.blm.gov/epl-front-office/eplanning/planAndProjectSite.do?methodName=dispatchToPatternPage&currentPageId=91868

The Wright Area FEIS analyzed the potential leasing and mining of federal coal reserves in response to LBAs filed by the operating mining companies in the Wyoming portion of the Powder River Basin. The Wright Area FEIS utilized the PRB Coal Review study for the cumulative effects analysis in the FEIS. The FEIS was used by BLM as the basis for the decisions to hold competitive, sealed-bid sales and eventual issuance of the Wright Area coal leases that had successful lease sales. The Wright Area FEIS is accessible at the following link: https://eplanning.blm.gov/epl-front-office/eplanning/legacyProjectSite.do?methodName=renderLegacyProjectSite&projectId=67033

In challenges to the leasing decisions, the Interior Board of Land Appeals and Wyoming District Court found that BLM's analysis of the environmental impacts of the leasing actions complied with NEPA. As previously described, the Tenth Circuit's 2017 remand was for only a single issue--the potential impacts to greenhouse gas emissions given current and projected coal supply and demand and fuel switching by electricity generating plants associated with the Wright Area FEIS No Action Alternative. This Remand EA clarifies and further addresses that issue.

1.5 Scoping and Public Involvement

1.5.1 Remand EA Public Participation

On March 5, 2018, the BLM Wyoming High Plains District Office (HPDO) issued a press release announcing that BLM was preparing a Wright Area Remand EA. The news release was posted at the following link:
https://eplanning.blm.gov/epl-front-office/eplanning/%20projectSummary.do?methodName=renderDefaultProjectSummary&projectId=97202

On August 2, 2018, the BLM Wyoming High Plains District issued a press release announcing a 30-day public comment period on the Wright Area Coal Leasing Tenth Circuit Court Remand Draft Environmental Assessment and availability for public review at the following link: https://go.usa.gov/xntFJ

On August 16, 2018, WildEarth Guardians and Sierra Club requested a 30-day extension on the comment period for the Wright Area Remand Draft EA. BLM granted the 30-day extension and issued a press release on August 27, 2018 announcing that BLM would accept public comments through October 4, 2018. The news release was posted at the following link:
https://www.blm.gov/press-release/blm-announces-30-day-extension-comment-period-wright-area-coal-leasing-draft-ea

During the official public comment period, BLM received the following hand-signed comment letters:

- The State of Wyoming Office of the Governor, signed by Matthew H. Mead, Governor;
- Campbell County Board of Commissioners, signed by Mark A. Christensen, Chairman;
- Thunder Basin Coal Company, signed by Lecia R. Craft, Environmental Supervisor;
- Powder River Basin Resource Council, signed by Shannon Anderson, Staff Attorney; and
- National Mining Association, signed by Katie Sweeney, General Counsel.

During this comment period, BLM further received four voluminous comment packages from the following entities:

- Western Organization of Resource Councils;
- Sierra Club;
- joint submission by Sierra Club/WildEarth Guardians; and
- joint submission by the Institute for Policy Integrity at New York University School of Law/Montana Environmental Information Center/Natural Resources Defense Council/Sierra Club/Union of Concerned Scientists.

For over a year, BLM has received letters and Remand EA comment emails outside the project's official public comment period. To date, BLM has received over 6,000 Wright Area Coal Lease comment emails similar to form letters with variants. Many emails appear to have been generated from the following website/email address: action@wildearthguardians.org. BLM continues to receive comments nearly every day concerning this project.

All comments were considered in the preparation of this court ordered Remand EA.

1.5.2 Prior Wright Area Public Participation Opportunities

Numerous opportunities for public involvement have been provided for throughout the entire BLM Wright Area project. To start, the Powder River Basin Regional Coal Team (RCT) reviewed all the Wright Area coal lease applications at public meetings held on April 19, 2006 and January 18, 2007 in Casper, Wyoming. Notices that announced the RCT public meetings were published in the Federal Register on February 9, 2006 and December 12, 2006.

BLM published a Notice of Intent (NOI) to prepare an EIS and Notice of Public Meeting in the Federal Register on July 3, 2007, in the Gillette News-Record newspaper on July 6, 2007, and in the Douglas Budget newspaper on July 11, 2007. The publications served as public notice that the Wright Area coal lease applications had been received, announced the time and location of the public scoping meeting, and requested public comment on the coal lease applications. On July 11, 2007, letters requesting public comment and announcement of the time and location of the public scoping meeting were also mailed to all parties on the distribution list. The public scoping meeting was held July 24, 2007 in Gillette, Wyoming.

The U.S. Environmental Protection Agency (EPA) published a notice announcing the availability of the Draft EIS in the Federal Register on June 26, 2009. Parties on the distribution list were sent copies of the Draft EIS, and copies were made available for review at the BLM offices in Casper and Cheyenne, Wyoming. The document was also available for review on the BLM Wyoming internet site. A 60-day comment period on the Draft EIS commenced with publication of the EPA's Notice of Availability (NOA) and ended on August 25, 2009.

BLM published a NOA/Notice of Public Hearing for the Draft EIS in the Federal Register on July 8, 2009. The BLM's Federal Register notice announced the date and time of the public hearing, which was held during the 60-day comment period on July 29, 2009 at 7:00 p.m. at the Clarion Inn in Gillette, Wyoming. The purpose of the public hearing was to solicit public comments on the Draft EIS and on the fair market value, the maximum economic recovery, and the proposed competitive sale of federal coal from the LBA tracts. BLM also published a notice of public hearing in both the Douglas Budget and Gillette News-Record newspapers on July 8, 2009. Comments that BLM received on the Draft EIS and how BLM considered these comments during the preparation of the Final EIS were included in Appendix I of the Final EIS.

A notice announcing the availability of the *Wright Area Coal Lease Applications Final EIS* (FEIS) was published in the Federal Register by the EPA on July 30, 2010. Parties on the distribution list were sent copies of the Final EIS at that time. The comment period for the Final EIS ended on August 30, 2010. The public review period was open for 30 days after EPA's

NOA published in the Federal Register. All comments that were received in a timely manner were considered in the preparation of the Wright Area Records of Decision (RODs).

The Wright Area coal tracts were additionally reviewed during the OSMRE/WDEQ mine permit process. The South Hilight Field, North Porcupine, and South Porcupine have all been permitted by the WDEQ for surface disturbance and coal mining activity.

Chapter 2

Proposed Action

2.1 Proposed Action

Under the Proposed Action, BLM is providing additional clarification, analysis, and documentation of the Wright Area FEIS No Action Alternative to address legal deficiencies identified by the Circuit Court and District Court pertaining to coal supply and demand suppositions and associated carbon dioxide emissions.

2.2 Discussion

This analysis was required by the District Court's remand. To comply with Court Order, BLM is not considering any other alternatives in this document.

Chapter 3

Affected Environment

3.1 Affected Environment

As previously mentioned, the Wright Area FEIS analyzed the potential leasing and mining of federal coal reserves in response to lease-by-applications (LBAs) filed by the operating mining companies in the Wyoming portion of the PRB. The Wright Area FEIS originally studied six LBA tracts, all located within the Wyoming portion of the PRB: North Hilight Field, South Hilight Field, West Hilight Field, North Porcupine, South Porcupine, and West Jacobs Ranch. After the FEIS was completed, two of the LBA tracts (West Jacobs Ranch and West Hilight Field) were withdrawn per company request. BLM issued four Records of Decision (RODs) for the other LBAs and these are the RODs that were challenged and upheld in this case by the District Court: South Hilight Field, North Porcupine, South Porcupine, and North Hilight Field.

Surface ownership in the Wright Area FEIS general analysis area consisted mainly of private lands intermingled with federal lands. In total, the Wright Area coal tracts, as delineated by BLM, contained about 65.1 percent private ownership, 34.4 percent federal ownership, and 0.5 percent state ownership. Livestock grazing is the primary land use while oil and gas production, wildlife habitat, communication and power lines, transportation, and recreation are all secondary land uses on both public and private lands. Areas of surface disturbance within and near the

Wright Area coal tracts include roads, oil and gas wells and associated production facilities, surface mine related facilities and activities, and activities associated with ranching operations. The oil and gas estate within the general Wright Area FEIS analysis area is federally and privately owned. Most of the federally owned oil and gas estate is already leased.

When the NEPA analyses and RODs for the Wright Area LBA tracts were prepared, the Black Thunder Mine (applicant of the North and South Hilight Field LBA tracts, W-164812 and W-174596 respectively) had approximately 10 years of remaining permitted coal reserves without the addition of these two tracts. The addition of the South Hilight was projected to add approximately 1.6 years of life to the mine, and the North Hilight was projected to add approximately 3.1 years, based on the 2008 production rate of 135 million tons per year.

The North Antelope/Rochelle Mine (NARO) (applicant of the North and South Porcupine LBA tracts, W-173408 and W-176095 respectively) had approximately 10 years of remaining permitted reserves without the addition of the two tracts. The addition of the North Porcupine was projected to add approximately 7.8 years of life to the mine, and the South Porcupine was projected to add approximately 3.6 years, based on a production rate of approximately 100 million tons per year.

Coal from the Wyoming PRB is almost exclusively used for electric power generation units across the U.S. As such, as discussed in the cumulative effects section of the Wright Area FEIS, BLM's analysis relied upon multiple interacting factors influencing the electric generation market including: the fuel mix based on market demand, available capacity within the coal market, pricing within the fuel market and the time frame for the market to adjust.

Chapter 4

Environmental Impacts and Consequences:

Clarifications, Additions, and Revisions

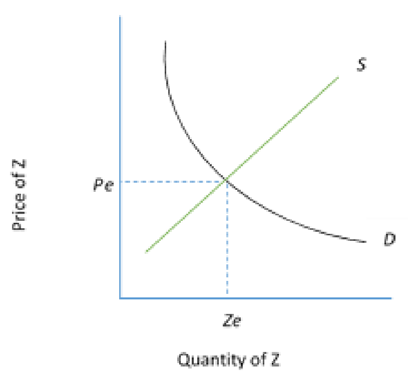
4.1 Introduction

This chapter further discloses and documents BLM's previous analysis of the Wright Area FEIS No Action Alternative. As previously mentioned, this Remand EA tiers to and incorporates by reference the Wright Area FEIS and RODs. This chapter specifically explains and describes the clarifications, additions, and revisions that BLM has made to address the District Court order and comments received on the Remand Draft EA. This Remand Final EA first describes generally the economic theory of supply and demand in order to provide a common understanding of the concepts and terms used through the remainder of the chapter. Next is a brief discussion on the complex and interacting systems that comprise the electric power system. The purpose of this discussion is to show how many factors and aspects of the overall electric power system can influence decisions regarding fuel sources, power generation technologies, generation units' usage, and transmission infrastructure in order to meet electricity demand. The discussion emphasizes coal supply and demand and its interplay with these various other factors. The focus on the electric power system is because almost all of the coal mined from the Wyoming PRB is used in coal-fired power plants to generate electricity. The Remand Final EA then elaborates on information available when the leasing decisions were made in 2010 to more effectively clarify and document the information the BLM considered in the leasing decision. The analysis concludes with a discussion on coal production and electric power system changes that have occurred over the past decade.

4.2 Supply and Demand Theory

Supply and demand is one of the most fundamental concepts in economics and is used for allocating scarce resources and analyzing competitive markets (Mankiw 2007). The law of supply claims that "other things equal, the quantity supplied of a good rises when the price of the good rises" and that the supply curve represents "the relationship between the price of a good and the quantity supplied" (Mankiw 2007 p. 71). The law of demand claims "other things equal, the quantity demanded of a good falls when the price of the good rises" and the demand curve represents "the relationship between the price of a good and quantity demanded" (Mankiw 2007 p. 65-66). Graph 4.2.1 represents the supply and demand relationship in a market diagram. In this graph, supply is represented graphically by an upward sloping line where the X axis is quantity supplied and the Y axis is price. Demand is represented graphically as a downward sloping line where the X axis is quantity demanded and the Y axis is price. Where *Pe* and *Ze* intersect this indicates that any product where these two curves meet is at the equilibrium price and quantity. It is the exact price where the quantity sold exactly equals the quantity demanded.

Graph 4.2.1. Supply and Demand Market Diagram



S: supply curve
D: demand curve
Pe, Ze: where the price and quantity demanded is in equilibrium

There are many factors that can determine the location and slope of the supply and demand curves. Some factors that determine demand are (Mankiw 2007; O'Sullivan, Sheffrin, and Perez 2014):

- Price of the product
- Consumers' incomes

- Price of substitute goods[2]
- Price of complementary goods[3]
- Consumers' preferences or tastes and advertising or other things that may influence preferences
- Consumers' expectations about future prices, which may cause consumers to stock up on goods if they anticipate price increases

And some factors that determine supply are (Mankiw 2007; O'Sullivan et al. 2014):

- Price of the product
- Wage paid to workers
- Price of materials
- Cost of capital
- State of production technology
- Producers' expectations about future prices
- Taxes paid to the government or subsidies

If one or more of these factors were to change it can lead to shifts in the supply or demand curves or both, thus leading to a different equilibrium price and quantity. For example, if prices of raw materials for a good increased greatly, this could cause a reduction in the good's supply with the supply curve moving up (or to the left). The shift in reduced supply would decrease quantity (*Ze* would shift to the left) and increase price (*Pe* would shift up).

A person is often interested in how much one variable (price or demand) will change in relation to the other variable. Elasticity measures the percent change in one variable resulting from a one-percent increase in the other variable (Pindyck and Rubinfeld 2005; O'Sullivan et al. 2014). Therefore, the price elasticity of demand would measure the percent change in the quantity demanded of a good resulting from a one-percent increase in the good's price (Pindyck and Rubinfeld 2005). In general, the price elasticity of demand is negative meaning that quantity demanded falls as the price for a good increases. The magnitude of that change in absolute terms can indicate whether the good is price elastic (price elasticity magnitude is greater than 1) or price inelastic (price elasticity magnitude is less than 1) (Pindyck and Rubinfeld 2005; O'Sullivan et al. 2014). When a good is price inelastic it means that, in general, a good will continue to be demanded regardless of price-at least to some degree. This generally occurs when there are no close substitutes for that specific good (Pindyck and Rubinfeld 2005). Just because a good is price inelastic does not mean that there will be no change in the quantity demanded, but that the percent change (decline) in quantity demanded is less than the percent change (increase) in price[4] (Pindyck and Rubinfeld 2005; O'Sullivan et al. 2014). The demand for goods tends to be more price elastic in the long run than in the short run since over the long run consumers can adjust to price changes and change their consumption behavior which can be more difficult in the short run.

[2] Substitute goods are when there are two related goods where an increase in the price of one leads to an increase in the quantity demanded of the other (Pindyck and Rubinfeld 2005; Mankiw 2007).

[3] Complementary goods are when there are two related goods where an increase in price of one leads to a decrease in the quantity demanded of the other (Pindyck and Rubinfeld 2005; Mankiw 2007).

[4] It is very rare for a good to have "perfectly inelastic demand" meaning there is zero quantity change as the price changes (Pindyck and Rubinfeld 2005; O'Sullivan et al. 2014). "The rare cases of perfectly inelastic demand are medicines—such as insulin for diabetics-that have no substitutes" (O'Sullivan et al. 2014 p. 83).

The supply and demand model is obviously a very simplified version of reality.[5] This model keeps everything other than price constant (*ceteris paribus*). It also represents a competitive market where "we assume many buyers and sellers, a homogeneous product, and that both buyers and sellers have the necessary information relating to all market transactions and can freely enter into or exit out of the industry" (Dahl 2015 p.69). This also assumes that no single buyer or seller can affect the market price (Mankiw 2007; O'Sullivan et al. 2014). In reality, markets are much more complicated with many factors influencing decisions especially in a market such as electricity generation as noted below.

"A static supply and demand model suggests increasing the marginal cost of the input leads to an increase in the product price, ceteris paribus. Likewise, an increase in demand leads to an increase in quantity demanded for the product, therefore, a higher price. Associated with these changes are increasing marginal costs caused by the increased use of the input. Economic theory, however, does not state how such relationships will respond in a dynamic framework which includes feedback in a non-ceteris paribus environment. Further complicating the issue are numerous locations using multiple inputs for power generation with different substitutability and complementary relationships" (Mjelde and Bessler 2009 p. 482).

As noted above and further discussed in the following section, supply and demand within the context of the electric power system does not easily conform to the norms of the general supply and demand model of other commodities. The uniqueness of the electric power system, which sets it apart from other commodities, is the limited storage capacity. This means that electricity must be simultaneously produced and supplied on demand through coordination by multiple actors in order to "forecast demand, schedule generation supply, and schedule exchanges with neighboring regions" (DOE 2017 p. A-31; see also GAO 2002; FERC 2015).

4.3 Electric Power System

4.3.1 Purpose and Components of the Power Generation System

The United States electric power system is comprised of multiple interacting components operated by numerous different entities and ownerships under a multitude of regulatory and policy mechanisms that differ across geography with the common goal of reliably supplying the necessary electricity to meet varying demand at a low-cost (GAO 2002; FERC 2015; DOE 2017). Essentially, the electric power system is an interconnected grid comprised of generating units, transmission lines, substations, distribution lines, end use, and system operations where operators must ensure reliable electricity generation that matches the demand of consumers instantaneously (Kaplan 2010; Campbell, Folger, and Brown 2013; FERC 2015; GAO 2015; EIA 2016a; NASEM 2016).

Although an in-depth discussion on all the various moving parts of the electric power system is out of the scope for this Remand EA, we provide a general discussion on key aspects of

[5] "The fundamental tool of mainstream economic methodology is *abstraction*. The economy is a complex system that interacts with other complex systems….The economist constructs an abstract *model*, a much simplified version of reality that strips away layer upon layer of detail…." (Randall 1981 p. 38).

generation, transmission, distribution and end use[6] in order to better understand the supply and demand concept and the Wright Area FEIS No Action Alternative. Specifically, the discussion focuses on describing the complexities involved with fuel source supply, cost for generation and the link to electricity demand and price. The discussion starts with factors affecting the electricity generation component with an emphasis on the role of coal production and use. Following this is an overall discussion on operation and coordination within the electric power system.

4.3.2 Generation, Dispatch, and Delivery

In order for electricity to be used by consumers, it first needs to be produced. Power plants (generating units)[7] generate electricity from primary fuel sources such as coal, natural gas, renewables, and uranium in order to supply the exact amount desired by customers when and where it is needed (FERC 2015; GAO 2015; DOE 2017). The type of generating technology[8], and its associated fuel source, utilized by power plants is often determined by the cost and performance of that technology. Costs associated with different generation types vary in terms of capital investment and operation and maintenance costs which affect the power plant's profitability. Capital investment costs are associated with building the plant or generating unit and include designing/ engineering the plant, transmission and fuel delivery facilities, financing, and construction costs (Kaplan 2008; EIA 2010a; Dahl 2015). The costs of the materials (particularly steel and concrete) and labor necessary for the construction of new power plants can influence whether a company invests in adding to its generation fleet (FERC 2008; FERC 2009).

Operation and maintenance costs include fixed costs such as labor, replacement equipment or maintenance materials, taxes and insurance and do not vary with differing levels of generation. Variable costs are the other type of operation and maintenance costs such as fuel and water, which often change in proportion to the change in generation (Dahl 2015; NETL 2015). Plants with higher capital costs tend to have lower operation and maintenance costs due to lower variable costs while lower capital cost plants have higher operation and maintenance costs (FERC 2015; GAO 2015).

Fuel source decisions and the efficiency of specific plant design and technology to convert fuel to electricity drive the variable costs of a power plant (Kaplan 2008; FERC 2015; Logan et al. 2017). Efficiency of a power plant is measured by the amount of fuel source needed in British Thermal Units (BTUs) to provide one kilowatt-hour of electricity, also known as the "heat rate" (Kaplan 2008, Logan et al. 2017). Heat rates only apply to power plants that use combustible fuels and are inverse to its level of efficiency-therefore a lower heat rate plant means a more efficient plant. Natural gas power plants tend to have a lower heat rate than coal power plants (Logan et al. 2017). Coal characteristics such as type and quality can greatly affect the generating efficiency of a power plant (MIT 2007). There are four types or ranks of coal:

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[6] The discussion here is meant to provide a general understanding of the complexities involved in the electric power system. For a more in-depth understanding of the overall electric power system, see FERC 2015, Lazar 2016, and DOE 2017.

[7] One power plant can have multiple generating units utilizing different generating technologies and fuel sources. Power plants and generating units will be used interchangeably in this Remand EA.

[8] Logan et al. 2017 provides an in-depth discussion on the generation component of the electric power system including technologies, costs, and environmental impacts.

anthracite, bituminous, sub-bituminous, and lignite coal. While anthracite coal is mostly used in the metals industry, bituminous, sub-bituminous, and lignite coal contribute to electricity generation. Of these three coal types, bituminous has a higher energy content (associated with amount of carbon) than sub-bituminous while lignite has the lowest energy content of the three (MIT 2007; Logan et al. 2017). Depending on the geological location and conditions where mined, coal will differ on sulfur and ash content. Power plants are generally designed to use a specific type of coal, with a specific BTU value and specific sulfur and ash levels. In general, generating efficiency can be decreased with higher sulfur content and high ash coals (MIT 2007). Generating units, as a whole, have "numerous limits in how they can be operated. These constraints must be respected to prevent the physical destruction of equipment" (Cramton 2017 p. 594). This would include ensuring proper fuel sources are utilized which can limit fuel switching within a specific generating unit.

The supply of a fuel source, including production and transportation, to a power plant also influences the plant's variable costs. There are numerous factors that contribute to the production and transportation costs of a fuel source in order to ensure fuel security and delivery to the power plant. For example the material and personnel costs associated with natural gas drilling, completion, and production would factor into the final price paid by the power plant to the supplier. Similarly, material and personnel costs associated with coal mining would factor in the price of coal paid by the power plant. Coal producers continue to look for ways to increase production and productivity thereby decreasing costs by:

- Increased automation to increase the efficiency of existing facilities and equipment;
- The addition of larger more efficient equipment;
- Moving production to lower stripping ratio mines;
- Mine consolidation to create larger mining complexes; and,
- The addition of contract miners with lower overhead and operating costs at existing mines.

One can see that the considerations by coal producers are reflective of factors that can influence supply as noted in Section 4.2.

One of the largest costs associated with a fuel source is transportation costs to the power plant whether it be by rail, road, or pipeline (Kaplan 2008; Logan et al. 2017). Each specific transportation method has differing costs associated with it, which can vary by geographic location. Additionally, there can be increased congestion and competition for rail lines, trucking capacity and pipeline capacity that can drive transportation costs up and can be especially problematic if there are limited transportation options from the fuel source to the power plant. Power plants often have additional stores of their necessary fuel source in the event of any transportation disruptions (Kaplan 2007; Kaplan 2008; FERC 2009). This allows the power plant to continue operations without having to use or find more expensive alternative fuel or electricity supplies (Kaplan 2007). For example, in 2008, total coal stocks were at 205.1 million short tons, of which 161.6 million tons were being stockpiled by the electric power sector and another 34.7 million short tons were held by producers and distributors (EIA 2010b). Trends from 1950 to 2008 in the total amount of coal stocks and the portion held by the electric power sector show considerable variation in the amount of coal stocks across that timeframe (EIA 2009a; EIA 2010b). This is due to economic forces such as reducing maintenance costs associated with coal inventories by decreasing the inventory, forecasted prices and anticipated demand, in addition to events affecting transportation infrastructure such as increasing rail congestion and weather related delays (Warwick 2002; Kaplan 2007; NERC 2007; Kelley and Osterholm 2008). Currently, most power plants that use coal stockpiled on average more than 60 days' worth of coal in 2017, but in recent years there's been considerable fluctuation in stockpile amounts for the same reasons mentioned above (EIA 2017a).

Generating units at power plants are often categorized by their generating technology and fuel source used, both of which can influence when and how they are dispatched. Dispatching is when a generating unit is called into service to meet electricity demand or load. Operators dispatch plants or generating units "with the simultaneous goals of providing reliable power at the lowest reasonable cost….plants are dispatched only when they are part of the most economic combination of plants needed to supply the customers on the grid" (FERC 2015 p. 48). Demand load for electricity varies by time of day, day of the week, season, and weather conditions (Kaplan 2008; FERC 2015). To account for these swings in demand load, different types of units are utilized. Baseload units are often used on a continuous basis since operators tend to maximize them to supply much of the needed electricity generation (MIT 2011; GAO 2015). This is in part due to baseload plants having a more limited ramping up and ramping down capability, thus they are not quick to respond to changes in electricity demand (Logan et al. 2017). Traditionally baseload plants have been coal, nuclear, and geothermal plants (and now more recently natural gas plants) and have had higher capital costs and lower variable costs (GAO 2002; Warwick 2002; Kaplan 2010; MIT 2011). Intermediate units, generally fueled by natural gas, are used to quickly ramp up or ramp down electricity output to match non-peak demand changes (Kaplan 2008; MIT 2011). To address the highest level of demand (peak demand) in a day, peak units are dispatched since these units can ramp up to full capacity/use in minimal time (in minutes) (Kaplan 2008; MIT 2011). Both intermediate and peak units tend to be less expensive to build but can have higher variable costs (Kaplan 2008; GAO 2015).

Wind and solar generating units are considered variable renewable units which are used as available to meet demand (Kaplan 2008; Logan et al. 2017). The use of renewable units are desirable given the lower cost of fuel (Logan et al. 2017). Due to the uncertainty of knowing when and for how long variable renewable units may produce electricity complicates dispatch determination, however more tools are becoming available to assist operators in incorporating variable renewable electricity generation (Logan et al. 2017). Additionally, the various changes in technology, fuel source costs, and integration of variable renewable units have allowed "power plant operators and engineering, permitting, and construction vendors adapt both coal and nuclear plants for more flexible operation. However, flexible operation can come at a cost: reduced efficiency, higher marginal emissions, and increased wear and tear on the equipment, which increases maintenance costs" (Logan et al. 2017 p. 20). Moreover, coal is often purchased well in advance of knowing natural gas price levels at the time of dispatch thus "large instantaneous shifts in coal burn may not be possible given the risks associated with fuel procurement" (Repsher, Heller, Mann, and Gaalaas 2018 p.26).

Once electricity has been generated it needs to be transmitted to the end user. This is done through interconnected high-voltage transmission lines that go from power plants to transformers at substations that reduce the voltage to a level safe for the distribution lines that connect to homes and businesses (DOE 2017; EIA 2018a). There are almost 170,000 miles of transmission lines with various voltage levels and six million miles of distribution lines across the United

States (MIT 2011). This transmission network has formed into three larger interconnected electric power grids or networks[9] which tend to operate independently (GAO 2002; Steinhurst 2011; EIA 2016a). Reliability of the transmission and distribution networks is a critical component of ensuring low cost electricity is delivered to the end user at the exact time it is needed. However, due to finite capacities (how much power it can carry),[10] transmission and distribution lines can become congested (Osborn and Kawann 2001; Steinhurst 2011; Campbell 2016). This means that the lowest cost power plants may not always be dispatched to supply the demanded electricity if the connected transmission lines are already at capacity (Warwick 2002; MIT 2011). Regulatory authorities are generally split: federal responsibility for transmission assets and state responsibility for distribution networks (DOE 2017). Investments into transmission networks are important as changes continue to occur with generating units and the size and locations of population centers demanding electricity. As new generating units, including wind and solar, are built and come online to replace retired generating units, additional transmission infrastructure is likely needed (Heiman and Solomon 2004). This is especially true when generating units are built away from existing power plants, transmission infrastructure, and population centers (Heiman and Solomon 2004; MIT 2011). This new transmission infrastructure can increase overall costs for the generation and distribution of electricity.

Ensuring adequate supply of electricity to reliably meet demand from having the necessary fuel sources, generating units, and transmission and distribution infrastructure requires considerable planning and coordinating by the various owners and operators of these different components. This requires understanding what the demand is and the factors that influence it. Electricity demand can be influenced by population changes (increased population tends to increase electricity use), weather[11] (a heat wave could increase electricity use due to air conditioner use), overall economic activity (greater economic activity usually increases electricity use), technological changes (increasing use of electric vehicles may increase electricity demand), and different regulations and policies (policies requiring energy efficient appliances/devices can help reduce electricity demand) (EIA 2008a; EIA 2010a; FERC 2015; Hibbard, Tierney and Franklin 2017). Understanding demand allows operators and owners of the various components to plan and coordinate future infrastructure needs. Planned power plant retirements, the amount of power they produced, planned new generation, and associated transmission and distribution infrastructure needs all should be considered and coordinated. Numerous changes have occurred throughout the last half century that have influenced this planning and coordinating of reliable electricity generation and distribution to changing electricity demands.

4.3.3 Operation, Coordination, and Regulation

Historically, the electric power system was planned and built around a vertically integrated system where one entity would provide the generation, transmission and associated services to the retail end user within a designated exclusive geographic area (franchise areas) (EIA 1996;

[9] The three interconnected networks are the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT) (EIA 2016a).

[10] "Power is proportional to the product of current and voltage; higher voltage and current correspond to higher power. Generators and other devices manipulate the distribution of power among lines by controlling voltages of the two ends of the lines" (MIT 2011 p. 32).

[11] FERC 2015 states that weather "is the single greatest driver of electricity demand and, thus is a major factor in grid operations" (p. 56).

Hogan 2008; MIT 2011). This operating entity (utility[12]) could be investor-owned (IOU), government-owned[13], or a member-owned cooperative (MIT 2011; Marston 2018); however, IOU utilities dominated in terms of number of customers served (EIA 1996; DOE 2017). This vertically integrated system allowed these utilities to operate as monopolies given the lack of competition in the power market in any given area (Joskow 2006; Hogan 2008; Pechman 2016). Due to this monopolistic aspect, the IOU entities were regulated at both state and federal levels, where generally a state regulatory entity would regulate operational standards to ensure reliability and regulate retail rates charged by the utility based upon the cost of service (cost-based pricing including operating costs and depreciated cost of the utility's assets) (FERC 2015; DOE 2017). Government owned utilities and cooperatives were assumed to operate based upon the customers' best interests when setting both operational standards and rates; however, there were still numerous regulations they had to abide by (Warwick 2002). This vertical integration system allowed for simpler planning and management since all infrastructure was owned and operated by one utility (Warwick 2002; NASEM 2016). Essentially this means that for a designated geographic area, one utility would be the central point responsible for dispatching generation units and the operation, maintenance and long term planning of generation, transmission, and distribution infrastructure.

Starting in the late 1970s through the 1990s, numerous regulatory changes occurred due to concerns over system reliability and potential for utilities to abuse the vertically integrated monopoly approach (EIA 1996; Hogan 2008; Kwoka 2008; MIT 2011). Many of these regulatory changes were intended to restructure the electric power system and industry from the traditional regulated vertically integrated monopoly approach to a system organized around the principles of competitive markets in order to increase efficiency and reduce prices (EIA 1996; Joskow 2006; MIT 2011; DOE 2017). The attempt at restructuring the electric power system and its associated market approach, however, has resulted in a "patchwork" system across the United States where different regions and states operate under different market systems from the traditional vertically integrated approach to one where ownership of the different components (generation, transmission, etc.) are broken up (unbundled) in various ways (FERC 2015; DOE 2017).

In regions that continued to use traditional regulated vertically integrated utilities, several states started to require that these utilities develop integrated resource plans (IRPs)[14] to meet customer demand typically for the next 10 to 20 years and update state regulators on a regular basis[15] (Chupka, Murphy, and Newell 2008; Barbose, Wiser, Phadke, and Goldman 2009). The IRPs should consider and assess increased need for electricity, supply and demand chains and the variety of generation options, and transmission and distribution factors (Hirst 1992). In addition

[12] An electric utility is one such "entity or instrumentality that owns and/or operates facilities…for the generation, transmission, distribution, or sale of electric energy primarily for use by the public" (EIA 1996 p. ix)
[13] Generally either federal, state or municipally owned (Warwick 2002).
[14] Integrated resource plans (IRP) for electric utilizes are defined in the Federal Energy Policy Act of 1992 as a "planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost" (FEPA 1992 §111(d) (19)).
[15] The frequency of updates depends on the state. A good review of state IRP requirements was done by Wilson and Peterson 2011.

to this long-range planning, utilities still had operational responsibility for ensuring reliability, balancing supply and demand, and dispatching generating units as economically possible given potential transmission and distribution constraints (FERC 2015). This includes working with adjacent system operators to coordinate dispatch and overall system infrastructure development. Retail rates would be set as discussed above under the historic vertically integrated system.

For the states and regions that moved forward with the market approach, this was often done by developing centrally organized markets run by regional transmission operators (RTOs) that required independent power producers (IPPs) to take over generating assets[16] and operate the generating component within a competitive wholesale electricity market[17] (Campbell 2016; Cramton 2017; DOE 2017). This means that IPPs sell their electricity on a wholesale market to other utilities, RTOs, or power "brokers" all of which can then resell the electricity on the wholesale market again or to distribution utilities or other retail service providers (Campbell 2016). Utilities could still own and operate their transmission and/or distribution systems. For states that set up retail competition[18], "rates would only include the cost of the distribution of electricity, while prices for electricity generation are determined competitively" (DOE 2017 p. A-17). Essentially, the competitive wholesale market for generation and secondarily, the retail competition where service providers compete for consumers are the cornerstones of this restructured market approach (Klitgaard and Reddy 2000; Cramton 2017).

Maintaining reliability and the operation of the electric grid when there are multiple owners and operators of the different components (power plants, transmission lines, substations, etc.) falls on entities known as balancing authorities[19] (FERC 2015; EIA 2016a). Balancing authorities maintain the electric grid operations including dispatching generating units to ensure adequate supply of electricity for the real-time demand within transmission and distribution capacities by meeting mandatory reliability standards issued by North American Electric Reliability Corporation (NERC) that were approved by the Federal Energy Regulatory Commission (FERC) (EIA 2016a). RTOs function as balancing authorities as well as those utilities that take on responsibility for a specific portion of the power system (EIA 2016a).

In a market oriented system, planning for infrastructure investments is difficult in part due to the various ownerships and market structures in different regions since the type of market structure influences how the owner will recoup investment costs. Generating units take years to build and are anticipated to continue operations for decades (Hogan 2008; Kaplan 2008). This is partly why owners and operators think on long time horizons to try and forecast what different fuel source costs will be, what the demand might be and how to best provide a reliable source of

[16] Meaning that incumbent utilities needed to "unbundle" and sell their generating assets and maintain their transmission and/or distribution components.
[17] This is a generalized explanation of a restructured electric power system market. There is considerable variation in ownerships, rate determination, as well as in the role competitive market forces may play in the overall electric power system.
[18] In 2017 only 14 states and the District of Columbia had programs that allowed consumers to purchase electricity from competitive retail suppliers (DOE 2017). Retail competition means that individual consumers can buy electricity from any number of suppliers (Klitgaard and Reddy 2000).
[19] NERC defines a balancing authority as "[t]he responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time" (NERC 2018 p. 4).

electricity in the most cost-effective manner, in addition to ensuring a connection to adequate transmission capacity. Due to the capital investment costs within the electric power sector and expected construction times for new generating units and transmission infrastructure, owners and operators are continually reviewing current information and data to determine best future options for generation and infrastructure on long time horizons (Hogan 2008; Barbose et al. 2009). Investments in transmission infrastructure is a difficult component which the market does not solve since current market processes make cost recovery of the investment inadequate to pursue (Cramton 2017). Additionally, even under this restructured market approach, distribution entities remain a monopoly utility (Cramton 2017).

This discussion about the electric power system, the various components, the numerous factors that can influence it, and the basic operational structure exemplify why this system does not fit within the normal supply and demand model. It's clear "that electricity markets are not anywhere near as straightforward as financial or even other commodity markets" (Weron 2002 p. 110). A basic assumption of the supply and demand model is that the market is "at least roughly competitive" (Pindyck and Rubinfeld 2005 p. 24). Utilities within the traditional vertically integrated system are known to have a monopoly within a geographic region, thus contradicting the supply and demand model assumption of being even "roughly" competitive (Burtraw, Palmer, and Heintzelman 2000; Hogan 2008). Within the vertically integrated system, there are not many buyers and sellers and buyers (consumers) only have one utility from which to purchase.

Even in the states and regions that have moved forward with a market approach, "a large number of nonmarket mechanisms have been imposed on emerging competitive wholesale and retail markets. These mechanisms include spot market price caps, operating reserve requirements, non-price rationing protocols, and administrative protocols for managing system emergencies" (Joskow and Tirole 2004 p. 1). These nonmarket mechanisms and price controls act to dampen or distort consumer reactions to potentially important market signals (Brown, Eckert, and Eckert 2017). The rationale for justifying the use of nonmarket mechanisms is due to the unique nature of electric power systems and the physical characteristics of electricity (Joskow and Tirole 2004; FERC 2015).

The electric power system is different from most other commodities in that electricity has become a necessity and consumers have few options and substitutes in the short term if prices rise (FERC 2015). This means that in the short term, electricity demand is price inelastic (Heiman and Solomon 2004; Bernstein and Griffin 2006; FERC 2015). Additionally, the lack of customer storage options means that customers cannot purchase extra electricity when prices are low to be used at a later date (FERC 2015). As noted by Heiman and Solomon (2004):

The failure of electric market restructuring and market liberalization to deliver anticipated benefits is not hard to understand once we take off the ideological blinders. As independent energy consultant Eugene Coyle argues, if the goal is lower rates, electric market deregulation cannot work for small businesses and residential consumers because electric service for them is nondiscretionary and demand inelastic in the short run. Thus, as large industrial users acquire low-cost service by threatening to disconnect from the grid, residential users are left with higher-priced supply when the providers discriminate against those with *inelastic demand in order to remain profitable (Coyle 2000, Coyle personal communication 2002)"* (p. 99).

This further illustrates the uniqueness of the electric power system. Generating units have limited fuel switching ability, dispatching of units may be determined by a different entity and transmission capabilities, while still maintaining reliability to meet instant demand. It is simplistic to assume that a change in coal price would relate to a similar change in electricity prices and thus change electricity demand. While fuel cost is one factor influencing electricity pricing, it is only one of numerous factors and regulations in what is generally a non-competitive market.

4.4 Electric Power Generation Trends and Projections

At the time of the Wright Area FEIS, the following trends and projections were identified. As discussed below these trends and projections indicated the continued need for coal to meet electricity generation demand into the future.

4.4.1 Electric Power Generation Trends and AEO 2010 Projections

While prior to the 1960s coal was consumed in the industrial sector and transportation sector (coal steam-driven trains and ships), most coal by the 1960s was used for electricity generation with 93% of all coal consumed in 2008 being in the electric power sector (EIA 2009a). Coal has increased its market share of net electric power generation since the 1950s through 2007 as Graph 4.4.1 shows (EIA 2009a). During this time, natural gas was the second largest fuel source used for electricity generation and steadily climbed since the 1990s through 2007 (see Graph 4.4.1). Nuclear energy (the third largest source) experienced growth from 1970 through 1990 but began leveling off in the early 2000s (see Graph 4.4.1).

The past electric generation trends help provide a context in which to view future projections of coal demand within the electric power sector. Given the complexity involved in the electric power system, for the NEPA analysis the BLM reviewed numerous documents and data with an emphasis on the *Annual Energy Outlook 2010* (*AEO2010*)[20] (EIA 2010a). The *AEO2010* and its associated documents discussed the current electric generation mix as well as provided projections of the electric generation mix through 2035. The *AEO* is produced by the Energy Information Administration (EIA), which is the statistical and analytical agency within the U.S. Department of Energy and is "the nation's premier source of energy information" (EIA 2018b).

The projections in the *AEO2010* (EIA 2010a) are produced using the National Energy Modeling System (NEMS) which is an economic and energy model of the U.S. energy markets which projects (approximately 25 years into the future), the production, consumption, conversion, import, export, and pricing of energy (EIA 2010a,c).

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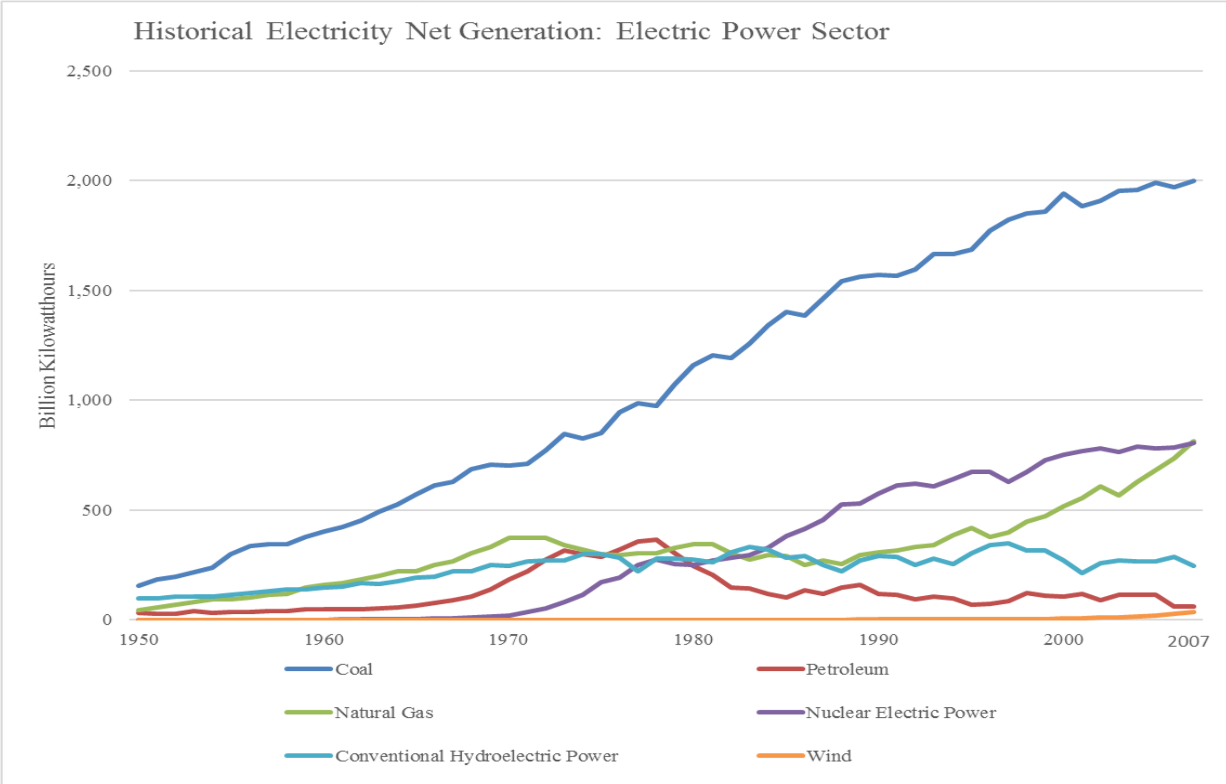
[20] "To assess the national electric generation portfolio and the mix of future electric generation technologies, BLM reviewed the *Annual Energy Outlook 2010* Report" (Wright Area FEIS p. 4-147).

Graph 4.4.1. Historical Electricity Net Generation: Electric Power Sector, 1950-2007



Source: EIA 2009a

Due to differences in energy supply, demand, and conversion factors across the United States, NEMS takes a regional approach which represents the regional differences in energy markets and transportation flows (EIA 2010c). NEMS uses various modules which "represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system" (EIA 2010a p. 195) including macroeconomic and international modules[21]. Additionally, NEMS incorporates the impacts and costs of current legislation and regulation that affect the various sectors (EIA 2010a). Although the *AEO2010* tends to emphasize the projections generated by NEMS for the *AEO2010* Reference case (scenario), projections were generated for 38 sensitivity cases "which explore important areas of market, technological, and policy uncertainty in the U.S. energy economy" (EIA 2010a p. 2). More information on the NEMS model, its various components, and constraints on BLM using the NEMS model for the Wright Area FEIS is included in Appendix A.

The discussion of the *AEO2010* projections for total electricity generation by fuel source type for the Reference case are based upon baseline economic growth of 2.4% per year from 2008 through 2035 (EIA 2010a). The Reference case sets the basis for examining the direction of future energy market trends under the assumption that current laws and regulations remain unchanged through the projections (EIA 2010a). In addition to the Reference case, projections

[21] NEMS modules include: Integrating, Macroeconomic Activity, International, Residential and Commercial Demand, Industrial Demand, Transportation Demand, Electricity Market, Renewable Fuels, Oil and Gas Supply, Natural Gas Transmission and Distribution, Petroleum Market, and Coal Market (EIA 2010a).

across a select number of cases that examine differing economic and energy market conditions are also discussed. These other cases and the reason for their inclusion are discussed below.

When the NEPA analysis and RODs for the Wright Area LBA tracts were prepared, *AEO2010* indicated that in 2008 total electricity generation derived from coal in the United States was approximately 48.5%, while 21.4% was from natural gas and 19.6 % from nuclear power (Table 4.4.1). Table 4.4.1 also indicates that in 2008 a little over nine percent of electricity was generated using renewable sources with the remaining electricity generated by petroleum or other sources.

Table 4.4.1: *AEO2010* Total Electricity Generation Market Shares in 2008 and Projections for 2025 and 2035 for Three Cases

		2025			2035		
	2008	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Coal	48.5%	45.5%	45.0%	43.9%	44.7%	43.8%	43.6%
Petroleum & Other Fuels	1.5%	1.5%	1.5%	1.5%	1.5%	1.4%	1.3%
Natural Gas	21.4%	17.7%	18.3%	19.5%	20.0%	20.8%	20.5%
Nuclear Power	19.6%	19.8%	18.6%	17.7%	18.5%	17.1%	16.5%
Renewable Sources	9.1%	15.3%	16.7%	17.4%	15.3%	17.0%	18.1%
Total Electricity Generation (Billion Kilowatts)	4115.9	4466.1	4769.5	5045.6	4766.3	5259.2	5749.4

Source: EIA 2010a

To project electricity demand and generation needs into the future, the NEMS electricity market module considers numerous operational, economic, and environmental factors such as existing capacity, fuel prices, operating costs, demand loads, emissions at generating units, new technologies, and potential options for new generation facilities while also interacting with the other NEMS modules (EIA 2010d). Projections from *AEO2010* indicate that in the Reference case, electricity demand is anticipated to increase by 27.8 percent from 2008 to 2035, approximately 1.0 percent growth per year (EIA 2010a). Since energy demand is anticipated to vary due to external economic conditions (EIA 2008a; EIA 2010a), *AEO2010* included projections for a Low Economic Growth case and High Economic Growth case where total electricity generation (demand) was approximately nine percent lower (Low Economic Growth case) or higher (High Economic Growth case) than the Reference case (EIA 2010a). As indicated in Table 4.4.1 it is projected that in all three cases the market share of coal in 2025 and 2035 decreases while still maintaining the largest market share in total electricity generation in both years. Across all three cases in 2025 and 2035 there is a considerable increase in the market shares of renewable sources for total electricity generation (see Table 4.4.1). This is in part due to Federal tax credits, state requirements for renewable electricity generation, and concerns about greenhouse gas emissions (EIA 2010a). In other words, *AEO2010* projections indicated that some variation in fuel source shares of electricity generation were anticipated to occur between

2008 and 2035, with an increasing use of natural gas and to a lesser extent renewable sources, and coal still comprising the largest market share (EIA 2010a).

Additionally, to examine how changes in coal production and transportation costs could influence fuel source decisions and electricity demand, *AEO2010* included a Low Coal Cost case and a High Coal Cost case. In the Low Coal Cost case coal mining productivity growth rates were assumed to increase at a rate of 3.2 percent per year through 2035 whereas in the Reference case productivity was assumed to decline by 0.3 percent per year and in the High Coal Cost case decline at an average rate of 3.0 percent per year (EIA 2010c). Coal mining wages, mine equipment and supply costs, and transportation rates were assumed to be lower in 2035 when compared to 2008 for the Low Coal Cost case and higher for the High Coal Cost case (see EIA 2010c p. 155 for more details).

As can be seen in Table 4.4.2, under both the Low Coal Cost and High Coal Cost cases for 2025 and 2035, coal was also projected to have the largest market share in total electricity generation (as it was projected to in the three previous cases discussed above). Given the higher costs in the future associated with the High Coal Cost case, it was projected that in 2035 coal will have 41.0 percent share of the electricity generation market with natural gas and renewable sources increasing to 22.1 percent and 18.1 percent respectively (Table 4.4.2). The Low Coal Cost case projected an increase in coal's market share from 2025 to 2035, going from 45.7 percent to 46.5 percent. However, when compared to the 48.5 percent market share for coal in 2008 (see Table 4.4.1) there is still an overall projected downward trend in coal's share of the electricity generation market (Table 4.4.2).

Table 4.4.2: *AEO2010* Total Electricity Generation Market Shares-Projections for 2025 and 2035 for the Low Coal Cost and High Coal Cost cases

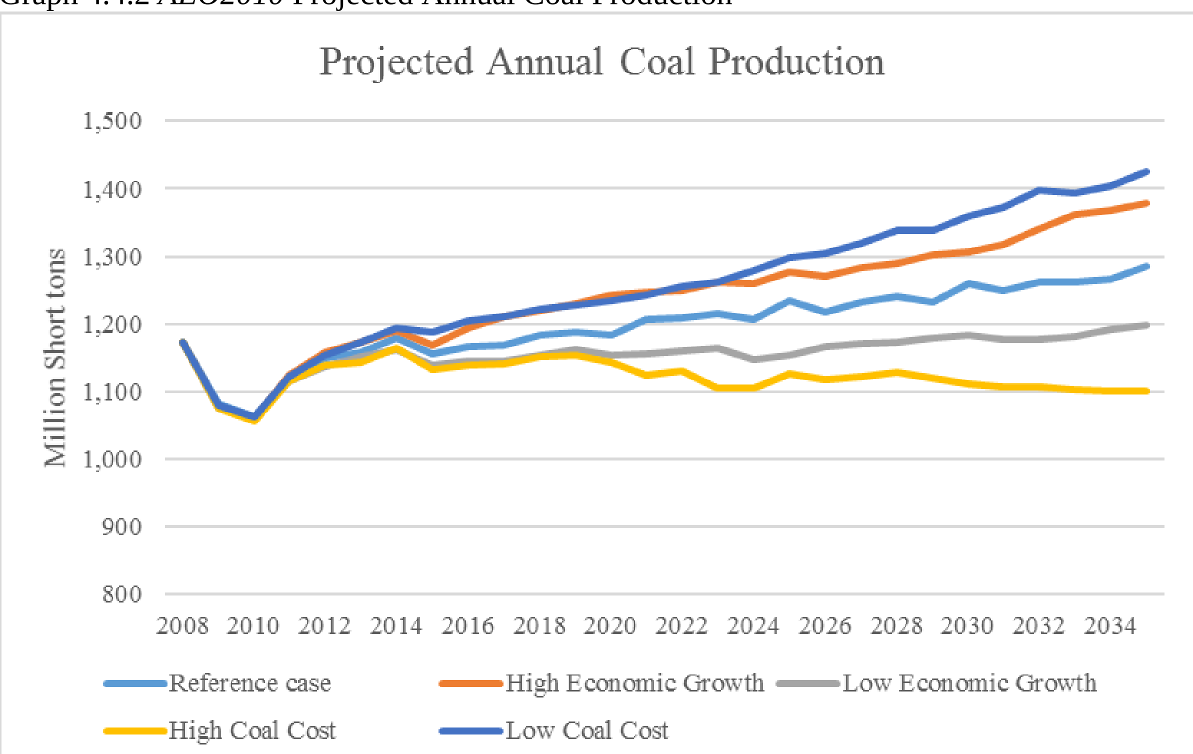
	2025		2035	
	Low Coal Cost	High Coal Cost	Low Coal Cost	High Coal Cost
Coal	45.7%	43.7%	46.5%	41.0%
Petroleum & Other Fuels	1.5%	1.5%	1.3%	1.4%
Natural Gas	17.9%	18.8%	19.5%	22.1%
Nuclear Power	18.5%	18.7%	16.7%	17.4%
Renewable Sources	16.3%	17.3%	16.0%	18.1%
Total Electricity Generation (Billion Kilowatts)	4789.0	4737.4	5302.1	5198.0

Source: EIA 2010a

As indicated by Table 4.4.1 and Table 4.4.2 electricity generation (demand) is anticipated to increase from 2008 to 2035 under these five cases as projected in *AEO2010* (EIA 2010a). In the Low Coal Cost case the amount of electricity generation in 2035 is similar to the amount projected for the Reference case (5302.1 versus 5259.2 billion kilowatts respectively) even with the considerably lower coal production and transportation costs. Projected electricity demand in 2035 is highest with the High Economic Growth case and lowest in the Low Economic Growth case indicating that electricity demand is driven more by overall economic conditions than coal production and transportation costs (EIA 2010a). The Coal Cost cases do indicate that coal costs can have a slight effect on fuel source decisions with a projected increase in natural gas and renewable sources, especially under the High Coal Cost case; however, coal was still projected to comprise the largest market share of total electricity generation in 2025 and 2035 under all five cases. Among the five cases, in 2035 the Low Coal Cost case projected the largest market share of electricity generation being met by coal (46.5 % versus 43.8% in the Reference case), while the market shares of natural gas and renewable sources in the Low Coal Cost case were projected to be similar to those in the Reference Case (19.5% and 20.8% for natural gas; 16.0% and 17.0% for renewable sources).

Although coal is projected to have lower market shares in future electricity generation, *AEO2010* indicates coal will continue to be a key fuel source through 2035 (EIA 2010a). As previously discussed, in 2008 total U.S. coal production had reached a record level of 1,171.8 million short tons with 54.1 percent produced in the Western region (EIA 2010b). In order to supply projected electricity generation demands and coal-to-liquid plants, *AEO2010* projected that coal production will continue to increase after 2010 albeit at a much slower rate for four of the five cases discussed (see Graph 4.4.2). In the High Coal Cost case, however, total coal production is projected to be lower through 2035 than 2008 production levels (see Graph 4.4.2). Even with potential reductions in coal market shares in meeting electricity generation demands, coal production is projected to continue with over 1,000 million short tons being produced each year for all five cases discussed (EIA 2010a).

Graph 4.4.2 *AEO2010* Projected Annual Coal Production



Source: EIA 2010a

To address coal demands of new and existing electric power plants across the U.S., *AEO2010* projected that in 2025 and 2035 most coal production will occur in the Western region for all five cases discussed (EIA 2010a). In particular, the Wyoming PRB was anticipated to produce a range of 40 to 50 percent of total U.S. coal production in all but the High Coal Cost case in 2025 and 2035 (see Table 4.4.3). Forecasted reductions in coal production in the Western region are slightly offset by small increases in coal production in the Interior region in the High Coal Cost case (EIA 2010a).

Table 4.4.3: *AEO2010* Projections of Wyoming Powder River Basin Coal Production as Percent of Total U.S. Coal Production

	Reference case	High Economic Growth	Low Economic Growth	High Coal Cost	Low Coal Cost
2025	43.7%	44.2%	43.1%	36.3%	47.0%
2035	42.9%	41.4%	42.9%	28.8%	49.6%

Source: EIA 2010a

Based on *AEO2010* projections and given that in 2008 the applicants associated with the four LBA tracts of interest for this Remand EA, had an average of approximately 10 years of coal already leased and permitted to mine without these LBA tracts, the BLM concluded that there would be continued coal demand for electricity generation, although perhaps at lower levels than was seen in 2008. The expectation that coal would continue to contribute to meeting electricity generation demands was also supported by data specific to the WY PRB as discussed below.

4.4.2 WY PRB production and use in power generation

In 2008 the Powder River Basin was the largest coal producing basin in the United States. The WY PRB contained all of the nation's 10 largest surface coal mines in 2008 (EIA 2010b), with vast reserves of low sulfur coal deposited in thick beds under relatively thin overburden cover. This results in low stripping ratio coal that can be recovered with efficient large-scale mining equipment throughout much of the basin (EIA 2010b). Coal throughout the WY PRB has similar composition and is ranked as sub-bituminous with calorific content ranging from 7500 to 9500 BTUs per pound. The coal in these LBA tracts are approximately 8800 BTU per pound. While this coal has lower heating content it remains in high demand due to its low cost and low sulfur content. A 2007 Congressional Research Service (CRS) report stated:

"*The Powder River Basin (PRB) in Wyoming and Montana is the nation's most important source of coal... PRB coal is in high demand due to its environmental and cost advantages. PRB coal emits fewer air pollutants when burned than most coal. The coal is found in seams dozens of feet thick located near the surface, so it can be strip-mined at low cost. Economical transportation, primarily by rail, has made it practical for PRB coal mined in Wyoming to fuel power plants in Georgia*" (Kaplan 2007 p. 7).

As was noted in the Wright Area FEIS, "[b]etween 1990 and January 2009, the BLM's Wyoming State Office held 25 competitive coal lease sales and issued 20 new federal coal leases containing almost 5.8 billion tons of coal using the LBA process"[22] (p. 4-4). An additional 12 LBAs in the WY PRB for over 3.7 billion tons of coal were pending at the time of the Wright Area FEIS (Wright Area FEIS p. 1-5 and 1-8).

As presented in Graph 1.1.1 of this Remand EA, leasing activity has generally paralleled production since decertification[23]. As stated in the Wright Area FEIS on page 4-4, "This is consistent with the PRRCT's [Powder River Regional Coal Team's] objective at the time of decertification to use the LBA process to lease tracts of federal coal to maintain production at existing mines." As previously described, the Black Thunder Mine and the North Antelope/Rochelle Mine (NARO Mine) had enough coal permitted to continue mining for approximately another 10 years at the time of the Wright Area FEIS. As such, under the Wright Area FEIS No Action Alternative rejecting the Wright Area LBA tracts would not have affected coal supply nor coal prices over the short term due to the approximately 10 years of continued mining.

In 2008, the United States Geological Survey (USGS) released the report "Assessment of Coal Geology, Resources, and Reserves in the Gillette Coalfield, Powder River Basin, Wyoming" (Luppens et al. 2008). This report calculated and predicted the amount of coal within the Gillette Coalfield, which included all the Wyoming PRB coal mines. The 2008 report found the total original coal resource for the 11 beds studied was 201 billion tons and the amount of recoverable coal was 77 billion short tons (Luppens et al. 2008). Recoverable coal is the available coal subtracting any coal under a stripping ratio[24] greater than 10:1 and subtracting mining and processing losses.

The 2008 study also looked at recoverable reserves that could be mined, processed, and marketed at a profit at the time of evaluation. This amount of coal is considered "the coal reserves". USGS estimated the coal reserve in the Gillette Coalfield to be 10.1 billion tons of coal (Luppens et al. 2008). This indicates that there would be plenty of coal available in the WY PRB to meet demand.

The 2008 USGS study is further supported by an updated expanded study that the USGS completed in 2015 which expanded the study to include not just the Gillette Coal field but the entire PRB in Wyoming and Montana (Luppens et al. 2015). In the 2015 study USGS found that the total coal resource for the PRB was 1.15 trillion short tons in place with 162 billion short tons estimated at a stripping ratio of 10:1 or less. A total of 25 billion short tons meet the definition of reserves as they can be economically produced at the time of publication (Luppens et al. 2015). This shows that beyond the Gillette Coalfield there is even more tons of comparable PRB coal in Montana and Wyoming.

The reserve base from the 2008 Gillette Coalfield study (Luppens et al. 2008) was further analyzed in a 2011 study by the John T. Boyd Company (Boyd 2011). This study examined the

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[22] These lease sales are listed in Table 1-1 and the leased tracts are shown in Figure 1-1 in the Wright Area FEIS.
[23] Decertification of the PRB region allows leasing to take place on an application basis, as discussed in the regulations at 43 CFR 3425.1-5.
[24] For surface mining, stripping ratio is the ratio of the amount of overburden expressed in cubic yards that has to be mined or removed to unearth or expose one ton of coal (U.S. BLM 2014).

individual mines to see the amount of reserves they had under lease, the amount of reserves they had in their current future plans, as well as how much recoverable coal was in their area of interest. According to the study, in addition to the amount of coal already permitted and in the LBA process as discussed above, there was another 10.1 billion tons of coal that is economically recoverable within the mines' areas of interest (Boyd 2011). This is over five times the quantity of coal in the subject LBA tracts. Even at the Black Thunder and NARO mines there is more coal available in the mines' areas of interest beyond the LBA tracts examined in the Wright Area FEIS. Boyd identified an additional 1.9 billion tons to the north and west of the Black Thunder Mine and an additional 1.5 billion tons of coal to the west of NARO Mine (Boyd 2011). This indicates that even without the subject four LBA tracts there was almost two times that amount of coal available in recoverable reserves at these two mines, without taking into consideration the coal available elsewhere in the PRB. Boyd's report further supports BLM's belief that based upon the 2008 USGS study and knowledge regarding coal amounts already permitted and in the LBA process, not only did the mines have approximately 10 years of permitted coal to continue mining, but that there was also ample reserves of coal with the same rank and qualities available for leasing in the WY PRB to supply demand in the event the subject four LBA tracts were not leased. Additionally, it should also be noted that if the subject LBA tracts were not leased, that there is nothing preventing the applicants from reapplying to leasing these lands in the future as part of a future LBA.

Transportation costs are an important factor determining the economic viability of WY PRB coal as a fuel source. This is especially important given that "PRB coal is shipped as far west as Oregon, throughout the entire Midwest, and as far south as Florida" (DOE 2007 p.11). The Basin is geographically isolated from the majority of utilities that consume WY PRB coal. Low mining costs and mine prices (free-on-board price (FOB))[25] combined with low transportation costs allow WY PRB coal to be transported long distances to power plants and still remain competitive on a basis of delivered cost per million BTU. This leads to a very busy rail line and can cause some congestion issues, which in turn can increase the delivered cost[26] of coal. There are only two railroads-Burlington Northern Santa Fe (BNSF) and Union Pacific (UP)-that transport coal from the PRB (DOE 2007) and any issues with the rail lines from the PRB can have a significant effect on coal production, coal costs and power plant operations. In May 2005 train derailments occurred on the rail lines that transport PRB coal stopping shipments of PRB coal due to the necessary clean-up, repair and maintenance of those rail lines. This resulted in "PRB coal production in Wyoming and Montana [being] curtailed for a couple of months, returning to pre-derailment levels by July 2005;" however, "electric utilities in the Midwest continued to experience problems with deliveries through Spring 2006" (DOE 2007 p. 2). The electric utilities affected by these rail line issues had to "reduce plant output and/or purchase spot supplies of coal and electricity, at significant expense" (DOE 2007 p. 2). This indicates the influence that reliable transportation and delivery of coal can have for power plant operations.

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[25] Free-on-board or freight-on-board "is a shipping term used in retail to indicate who is responsible for paying transportation charges" (Hudson 2018). Generally this means coal prices are the price of the coal at the coal mine before the cost of insurance, freight, and credit (EIA 2019a).

[26] Delivered cost of coal refers to the cost of the coal, plus the invoice price of coal, transportation charges, taxes, commissions, insurance, and expenses associated with leased or owned equipment to transport the coal (EIA 2019b).

Whereas for other mines transportation costs may account for approximately 20 percent of total costs of coal shipments to the power plant, shipment costs from the PRB can be as high as 59 percent of total costs (EIA 2011). For example, in 2008 the estimated FOB price of coal at the Black Thunder Mine was $15.22 and the average delivered cost for the year was $30.15 (S&P Global 2019). For WY PRB coal delivered to the Midwest or the Southeast, it might not be less expensive on a delivered basis than more expensive coal locally sourced (Repsher et al. 2018). This could be important in the Wright Area FEIS No Action Alternative if the PRB was not able to produce enough coal to meet the demand to replace the coal from the subject LBA tracts, there are opportunities for coal from other basins, like the Illinois Basin, to meet some of the demand without raising the price of coal.

In the preparation of the Wright Area FEIS NEPA analysis and RODs, BLM was aware that disruptions and costs associated with the transportation and delivery of PRB coal caused electric utilities to examine fuel switching capabilities within their coal-fired generation units. The unexpected reduced coal supply in 2005 did affect prices in the immediate future (DOE 2007); however, many of the utilities had limited ability to switch fuels since there were "many local potential constraints on the expansion of backup fuel use at coal-fired electricity generators, including air quality regulations, water protection rules, zoning and building codes, transportation codes and infrastructure, and power market structure" (DOE 2007 p. 18, see also EPRI 2000; GAO 2008; Geisbrecht and Dipeitro 2009). A Government Accountability Office (GAO) report in 2008 evaluated the ability to switch coal-burning power plants to natural gas and concluded that conversion is unlikely due to limited natural gas infrastructure (pipelines and storage capacities near existing coal plants) and potential regulatory and technical challenges (GAO 2008). While converting a coal-fired plant to burn only natural gas is technically feasible, GAO reports that "burning natural gas at an existing coal plant would require a pipeline with the ability to meet the plant's fuel supply requirements. If not, a new gas pipeline would have to be sited, permitted, designed, and constructed" and that "a major fuel-switching program would require a nationwide natural gas infrastructure construction program. This would require expansion of interstate and intrastate pipelines to transport increased volumes of natural gas. Furthermore, existing plants and local natural gas distribution systems would have to increase their storage capacity" (GAO 2008 p. 15).

Although coal-fired power plants have several options to reduce emissions such as co-firing with other lower emission fuels, retrofitting plants with carbon capture and sequestration and other technologies to reduce emissions, and refurbishing the plant to increase the plant's efficiency, these alterations can take considerable capital investment (EPRI 2000; GAO 2008; Geisbrecht and Dipeitro 2009). Instead of re-tooling existing coal-fired plants, it is often more cost-effective for utilities to utilize natural gas plants with excess capacity or build new natural gas generation units (GAO 2008). Although excess capacity at existing natural gas combined cycle power plants could potentially displace 32 percent of coal generation, it is improbable due to transmission system factors, system dispatch factors[27] and fuel source costs, supply, transportation and storage (Kaplan 2010).

[27] "System dispatch refers to the pattern in which power plants are turned on and off, and their power output ramped up and down, to meet changing load patterns" (Kaplan 2010 p. 18).

Additional studies, completed prior to the Wright Area FEIS completion, (Dahl and Ko 1998; Ko and Dahl 2001; Tuthill 2008) examined how in electric power generation fuel source demands are influenced by fuel prices (price elasticity of demand as discussed in Section 4.2). Of the fuels studied at that time (coal, natural gas, and oil) coal demand was actually the least sensitive to coal prices, meaning the price elasticity of demand for coal in electric power generation was price inelastic (also known as own-price inelastic). Additionally, coal demand in relation to changes in oil and natural gas prices was found to be cross-price inelastic[28] (Dahl and Ko 1998; Ko and Dahl 2001; Tuthill 2008). As mentioned in Section 4.2, when a good is price inelastic, that does not mean that there will be no change in the quantity demanded – in this case it means that the percent change (decline) in the quantity of coal demanded for electric power generation is less than the percent change (increase) in price of either coal or to a lesser degree oil and natural gas. Furthermore, there are numerous factors other than just fuel price that influence the displacement of coal. These other factors include the overall configuration and capacity of the transmission and distribution systems, how generating units are dispatched, the availability of other fuel sources and associated infrastructure (such as natural gas pipelines), as well as overall reliability requirements (Kaplan 2010). This indicates that under the No Action Alternative, as analyzed for the Wright Area FEIS, coal, oil, and natural gas prices for electric power generation would likely not cause significant changes in the use of/demand for coal. More recent changes in the electric power system and coal production and cost are discussed in Section 4.6.

4.5 GHG Emissions

There are several gases in the earth's atmosphere that contribute to the "greenhouse effect" or the trapping of the sun's warmth near the earth's surface. Gases that contribute to the greenhouse effect are called greenhouse gases (GHGs). Increases in atmospheric concentrations of these gases are the primary cause of global warming and climate change. The three most common GHGs associated with fossil fuel development and combustion related emissions are carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). BLM typically analyses these GHG emissions and presents results in terms of CO_2 equivalents (CO_2e). In the Wright Area FEIS, the BLM analyzed greenhouse gas (GHG) emissions that could result from coal mining and associated mining operations and the indirect emissions associated with the combustion of coal to generate electric power. Emissions of GHGs were estimated for mining operations including all types of carbon fuels used in the mining operations, electricity used on site (i.e., lighting for facilities, roads, and operations and electrically powered equipment and conveyors) and mining processes (i.e., blasting, coal fires caused by spontaneous combustion and methane released from exposed coal seams (Wright Area FEIS p. 3-324-325). Direct GHG emissions associated with mining operations were projected to increase at the Black Thunder and NARO mines if the North Hilight Field, South Hilight Field, North Porcupine, and South Porcupine LBA Tracts were added to the mining operations. The increases in GHG emissions were expected to result from the additional fuels (especially diesel) that would be used due to the increased coal and overburden haul distances, as well as increased use of electricity and explosives related to increasing overburden thicknesses during mining operations. Table 3-24 in the Wright Area FEIS (p. 3-325) indicated that for all six LBA tracts analyzed, the estimated annual GHG emissions associated with the mining of that coal (including methane emissions vented from exposed coal) would be 2.50 million metric tonnes (MMmt) per year from the

[28] Cross-price elasticity of demand is "the percent change in the quantity demanded for a good that results from a 1-percent increase in the price of another good" (Pindyck and Rubinfeld 2005 p. 34).

three mines and the LBA tracts. Estimated GHG emissions from existing mining operations in 2007 were 1.25 MMmt per year (MMmt/yr). The FEIS further discussed that based upon estimates from the Center for Climate Strategies the GHG emissions associated with the 2007 existing mining operations (as analyzed in the FEIS) represented 2.22 percent of the 2010 state-wide GHG emissions. With the addition of the six LBA Tracts analyzed in the FEIS, the estimated total GHG emissions associated with mining operations at the applicant mines would represent 3.61 percent of the projected 2020 state-wide emissions (Wright Area FEIS p. 3-326).

Additionally, the estimated emissions of GHGs from the combustion of the coal produced in 2008 and under the alternatives were also discussed in the FEIS. The applicant mines produced 228.3 million tons of coal in 2008 and the FEIS states that combustion of the recovered coal to produce electricity resulted in about 378.7 MMmt of GHG emissions, or about 5.4 percent of the total estimated anthropogenic GHG emissions produced in the U.S. in 2008 (Wright Area FEIS p. 4-139). The Wright Area FEIS further states that under the No Action Alternative, GHG emissions associated with combustion of the coal produced by the applicant mines "would be extended at about this level for up to approximately 10 years beyond 2008, while the mines recover their remaining estimated 2,483 million tons of currently leased coal reserves" (Wright Area FEIS p. 4-139-141). GHG emissions from combustion of the coal produced are also estimated for the Proposed Action and Alternative 2, both as the total and the average per year for each specific LBA tract. (Wright Area FEIS Table 4-39 on page 4-140).

This Remand EA includes an updated and expanded discussion of estimated indirect GHG emissions for the No Action Alternative from the FEIS and other scenarios. The following discussion of GHGs is included in response to changes in information, methodology, and court ordered direction since the analysis of GHGs was completed for the FEIS. Changes addressed in this discussion include:

- Withdrawal of two LBA tracts (West Hilight and West Jacobs);

- Global warming potentials (GWPs) for the greenhouse gases for two different time horizons;

- Indirect GHG emissions including downstream combustion and transportation; and,

- Direction from the District Court to address BLM's claim in the FEIS that "…it is not likely that selection of the No Action [A]lternative would result in a decrease of U.S. CO_2 emissions attributable to coal mining and coal-burning power plants…"

For this Remand EA, indirect emissions of GHGs were analyzed for the No Action Alternative (no leasing of the six LBA tracts) and were compared to the Selected Alternative (Alternative 2) from the FEIS. The Wright Area FEIS analyzed six LBA tracts; however, after the FEIS was completed two tracts were withdrawn per company request. Therefore GHG emissions discussed in this section regarding all six LBA tracts likely overestimate potential emissions of the remaining four tracts. Direct emissions of GHGs from coal mining and coal mining operations are extensively and adequately addressed in the FEIS and represent only a small fraction of total emissions when compared to the indirect emissions, so they are not reanalyzed in this Remand EA. The indirect emissions assessed herein include GHG emissions from the combustion of recovered coal and from the rail transportation of the recovered coal. Emissions from these fossil fuel combustion sources primarily consist of carbon dioxide (CO_2) with small amounts of methane (CH_4) and nitrous oxide (N_2O). Emissions are presented in terms of CO_2 equivalents (CO_2e) which is a unit that describes the different GHGs in a common unit taking into account each GHG's global warming potential.

Each type of GHG has a global warming potential (GWP) that accounts for the intensity of its heat trapping effect and its longevity in the atmosphere. GWP values allow for a comparison of the impacts of emissions and reductions of different gases. According to the Intergovernmental Panel on Climate Change (IPCC), GWPs typically have an uncertainty of ±35 percent. GWPs have been developed for several GHGs over different time horizons including 20 year, 100 year, and 500 year. The choice of emission metric and time horizon depends on the type of application and policy context. The 100-year GWP was adopted by the United Nations Framework Convention on Climate Change and its Kyoto Protocol and is now used widely as the default metric. In addition, the EPA uses the 100 year time horizon in its Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2016 (EPA 2018a), GHG Reporting Rule requirements under 40 CFR Part 98 Subpart A, and in its science communications to be consistent with the IPCC Fifth Assessment Report, Climate Change Synthesis Report, 2014 (IPCC 2014). In this Remand EA, the BLM uses the 100-year GWP time horizon consistent with EPA and IPCC in its GHG emission calculations and also includes a comparison of GHG emissions using the 20 year time horizon for illustrative purposes. The GWPs used for CO_2 are 1 for both time horizons and for CH_4 are 28 for 100-year and 84 for 20-year time horizons. The GWPs used for N_2O are 265 for 100-year and 264 for the 20-year time horizons.

Tables 4.5.1 through 4.5.10 present the results of calculations completed to assess indirect emissions from the No Action Alternative as described in the Wright Area FEIS. In addition, results are presented for the Selected Alternative (Alternative 2 in the FEIS) and the Selected Alternative less the two LBA tracts that were withdrawn after the FEIS was completed. In addition, estimated emissions based on actual production in 2017 are presented for comparison. These additional scenarios are presented to illustrate the difference in potential emissions between no leasing and leasing and to compare to recent actual emissions. Table 4.5.1 presents an overview of the indirect emissions while Table 4.5.2 compares the summary emissions to various national metrics.

Tables 4.5.3 through 4.5.6 present estimated GHG emissions attributable to the downstream combustion for electricity generation of the coal produced under the Wright Area FEIS No Action Alternative and other scenarios. The calculations are based on emission factors developed using data from EIA and EPA. The EIA's Emissions Factors and EIA Coal Data Browser lists an average CO_2 emissions factor for Wyoming coal of 212.7 pounds of CO_2 per million British Thermal Unit (MMBTU) (EIA 1994) with an average heat content of 8,716 BTU/lb (EIA 2019c) . Emission factors for CH_4 and N_2O for stationary combustion of sub-bituminous coal used were 0.42 lb/ton and 0.06 and were obtained from EPA's Emission Factors for Greenhouse Gas Inventories, March 2018 (EPA 2018b).

Tables 4.5.7 through 4.5.10 present estimated GHG emissions attributable to the transport of the produced coal under the Wright Area FEIS No Action Alternative and other scenarios by rail using diesel locomotives. The calculations are based on emission factors developed using data from BNSF Railroad and EPA. BNSF developed a fuel efficiency factor for diesel locomotives of 849 ton-mile/gallon in its BNSF Corporate Responsibility and Sustainability Report, 2017 (BNSF 2017). EPA emission factors for diesel locomotives of 20.9 lb/gal for CO_2, 0.0018 lb/gal for CH_4, and 0.0006 lb/gal for N_2O as presented in EPA's Greenhouse Gas Inventory Guidance, Direct Emissions from Mobile Combustion Sources, Jan. 2016 (EPA 2016). The average transport distance in miles was derived by using 2017 transport data for each mine obtained from EIA's Coal Data Browser (EIA 2019d). In 2017, coal from the Black Thunder Mine was shipped almost exclusively by rail to more than 80 different locations throughout the U.S. and coal from NARO Mine was shipped by rail to more than 160 locations. An average transport distance of 1,037 miles for the Black Thunder Mine and 1,121 miles for NARO Mine was used in the calculations.

Under the Wright Area FEIS No Action Alternative, GHG emissions estimates are based on the assumption that the LBA tracts would not be leased, but the existing leases at the adjacent Black Thunder, Jacobs Ranch, and NARO mines would be developed according to the existing approved mining plans. At the time that the GHG analysis was compiled for the Wright Area FEIS, there was approximately 10 years of coal reserves left under existing mining plans at the existing rate of production. The No Action Alternative emissions estimates show that annual indirect GHG emissions attributable to electricity generation combustion and rail transport would be approximately 461 MMmt/yr and 4,403 MMmt for the remaining life of the mines. Under the Wright Area FEIS Selected Alternative the proposed six tracts would be leased. The estimated annual indirect GHG emissions under this scenario (including the emissions from the remaining 10 years for the existing mines) would be approximately 1,084 MMmt/yr and 11,824 MMmt for the remaining life of the mines. The difference in indirect GHG emissions between leasing and not leasing, therefore, is approximately 623 MMmt/yr and 7,421 MMmt/yr for the life of the mines. This difference represents approximately 9.6% of total U.S. GHG emissions in 2017. It is important to note that this estimate of the difference in indirect emissions between the Wright Area FEIS No Action and Selected Alternative scenarios does not take into account other factors that could influence the difference such as economic and regulatory drivers, changes in technology, or availability of replacement energy sources. Therefore, the actual difference in emissions between leasing and not leasing could range from 0 to significantly more than the estimated amounts and BLM cannot make a definitive statement about the degree to which regional or global GHG emissions would be impacted by leasing versus not leasing the proposed LBA tracts.

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Table 4.5.1: Summary of Wright Area FEIS No Action Alternative and Other Scenarios Indirect GHG Emissions

Scenario	Annual GHG Emissions from Downstream Combustion + Rail Transport CO_2e 20-year (MMmt/yr)	Annual GHG Emissions from Downstream Combustion + Rail Transport CO_2e 100-year (MMmt/yr)	Life of Mine GHG Emissions from Downstream Combustion + Rail Transport CO_2e 20-year (MMMmt)	Life of Mine GHG Emissions from Downstream Combustion + Rail Transport CO_2e 100-year (MMMmt)
No Action	464	461	4,431	4,403
Selected Action	1,090	1,084	11,898	11,824
Selected Action minus withdrawn tracts	790	785	8,128	6,945
Actual - 2017	296	295	2,956	2,944

Table 4.5.2: Comparison and Equivalency of Wright Area FEIS No Action Alternative and Scenario Emissions to U.S. Emissions

Scenario	Annual GHG Emissions from Downstream Combustion + Rail Transport CO2eq 100-year (MMmt/yr)	Annual GHG Emissions as a percent of Total U.S. GHG Emissions 2017	Annual GHG Emissions as a percent of GHG Emissions from U.S. Energy Sector 2017	Annual GHG Emissions Equivalent to CO_2 Emissions from Number of Power Plants	Annual GHG Emissions Equivalent Emissions Avoided by Number of Wind Turbines
No Action	461	7%	27%	118	98,000
Selected Action	1,084	17%	62%	278	230,000
Selected Action minus withdrawn tracts	785	12%	45%	202	166,000
Actual - 2017	295	5%	17%	76	63,000

U.S. Total GHG Emission in 2017 = 6,472 MMmt

U.S. Energy Sector Emissions in 2017 = 1,734 MMmt

Source: *EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks, Public Review of Draft U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990-2017 (EPA 2019)*

Table 4.5.3: Wright Area FEIS No Action Alternative GHG Emissions from Electricity Generation Combustion

Mine	Current and Future Coal Production Rate (million tons/yr)	No Action Remaining Mine Life (years)	No Action Remaining Mineable Coal Reserves (million tons)	No Action Annual GHG Emissions from Downstream Combustion CO_2e 20-year (MMmt/yr)	No Action Annual GHG Emissions from Downstream Combustion CO_2e 100-year (MMmt/yr)	No Action Life of Mine GHG Emissions from Downstream Combustion CO_2e 20-year (MMmt)	No Action Life of Mine GHG Emissions from Downstream Combustion CO_2e 100-year (MMmt)
Black Thunder	135	9.3	1,169	230	229	2,141	2,128
North Antelope/ Rochelle	95	9.9	934	162	161	1,604	1,594
Jacobs Ranch	40	9.6	379	68	68	655	651
			Total No Action Emissions =	***460***	***458***	***4,400***	***4,372***

Table 4.5.4: Wright Area FEIS Selected Alternative GHG Emissions from Electricity Generation Combustion

Mine	LBA Tract	Selected Alternative Additional Mine Life (years)	Selected Alternative Estimated Additional Recoverable Coal (million tons)	Selected Alternative Annual GHG Emissions Downstream Combustion CO2e 20-year (MMmt/yr)	Selected Alternative Annual GHG Emissions Downstream Combustion CO2e 100-year (MMmt/yr)	Selected Alternative Life of Mine GHG Emissions Downstream Combustion CO2e 20-year (MMmt/yr)	Selected Alternative Life of Mine GHG Emissions Downstream Combustion CO2e 100-year (MMmt/yr)
Black Thunder	South Hilight	2.4	320	230	229	5,626	5,591
	North Hilight	5.0	669	230	229		
	West Hilight	7.8	1,056	230	229		
North Antelope/ Rochelle	South Porcupine	4.3	405	162	161	3,621	3,598
	North Porcupine	8.2	777	162	161		
Jacobs Ranch	West Jacobs	28.5	1,142	68	68	2,599	2,583
			Total Selected Action Emissions =	***1,083***	***1,076***	***11,846***	***11,772***

Table 4.5.5: Wright Area Selected Alternative minus withdrawn LBA tracts GHG Emissions from Electricity Generation Combustion

Mine	LBA Tract	Selected Alternative Additional Mine Life (years)	Selected Alternative Estimated Additional Recoverable Coal (million tons)	Selected Alternative Annual GHG Emissions Downstream Combustion CO2e 20-year (MMmt/yr)	Selected Alternative Annual GHG Emissions Downstream Combustion CO2e 100-year (MMmt/yr)	Selected Alternative Life of Mine GHG Emissions Downstream Combustion CO2e 20-year (MMmt/yr)	Selected Alternative Life of Mine GHG Emissions Downstream Combustion CO2e 100-year (MMmt/yr)
Black Thunder	South Hilight	2.4	320	230	229	3,826	2,670
	North Hilight	5.0	669	230	229		
	West Hilight	0.0	0	0	0		
North Antelope/ Rochelle	South Porcupine	4.3	405	162	161	3,621	3,598
	North Porcupine	8.2	777	162	161		
Jacobs Ranch	West Jacobs	0	0	0	0	655	651
Total Selected Action minus withdrawn tracts Emissions =				***784***	***780***	***8,102***	***6,919***

Table 4.5.6: Estimated Actual 2017 GHG Emissions from Electricity Generation Combustion

Mine	2017 Coal Production Rate (million tons/yr)	Estimated Remaining Mine Life (years)	Remaining Mineable Coal Reserves (million tons)	2017 Annual GHG Emissions from Downstream Combustion CO_2e 20-year (MMmt/yr)	2017 Annual GHG Emissions from Downstream Combustion CO_2e 100-year (MMmt/yr)	2027 Life of Mine GHG Emissions from Downstream Combustion CO_2e 20-year (MMmt)	2027 Life of Mine GHG Emissions from Downstream Combustion CO_2e 100-year (MMmt)
Black Thunder	70.51	10	705	120	119	1,202	1,195
North Antelope/ Rochelle	101.6	10	1,016	173	172	1,733	1,722
Jacobs Ranch	0	0	0	0	0	0	0
Total 2017 Emissions =				***293***	***292***	***2,935***	***2,917***

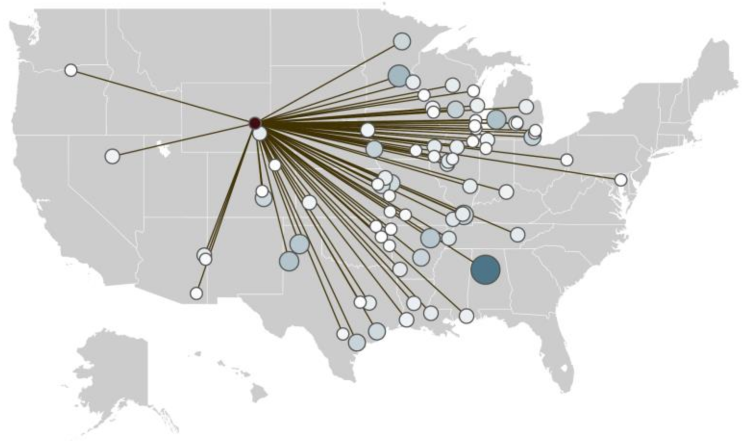


Figure 4.5.1: Rail Transport of Coal from Black Thunder Mine in 2017
Source: EIA Coal Data Browser

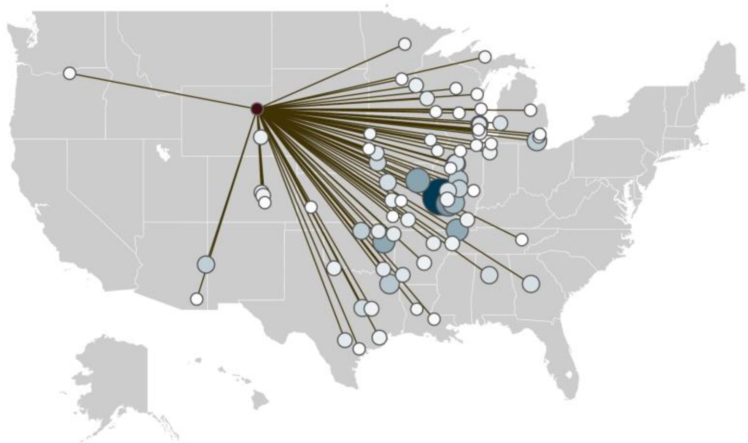


Figure 4.5.2: Transport of Coal from North Antelope/Rochelle Mine in 2017
Source: EIA Coal Data Browser

Table 4.5.7: Wright Area FEIS No Action Alternative GHG Emissions from Rail Transport

Mine	Production Rate (million tons/yr)	No Action Remaining Mine Life (years)	Average Rail distance (miles)	No Action Annual GHG Emissions from Rail Transport CO_2e 20-year (MMT/yr)	No Action Annual GHG Emissions from Rail Transport CO_2e 100-year (MMT/yr)	No Action Life of Mine GHG Emissions from Rail Transport CO_2e 20-year (MMT)	No Action Life of Mine GHG Emissions from Rail Transport CO_2e 100-year (MMT)
Black Thunder	135	9.3	1,037	1.6	1.6	14.7	14.7
North Antelope/ Rochelle	95	9.9	1,121	1.2	1.2	11.9	11.9
Jacobs Ranch	40	9.6	1,037	0.5	0.5	4.5	4.5
Total No Action Rail Emissions =				***3.3***	***3.2***	***31.2***	***31.0***

Table 4.5.8: Wright Area FEIS Selected Alternative GHG Emissions from Rail Transport

Mine	LBA Tract	Selected Alternative Additional Mine Life (years)	Average Rail distance (miles)	Selected Alternative Annual GHG Emissions Rail Transport CO2e 20-year (MMT/yr)	Selected Alternative Annual GHG Emissions Rail Transport CO2e 100-year (MMT/yr)	Selected Alternative Life of Mine GHG Emissions Rail Transport CO2e 20-year (MMT/yr)	Selected Alternative Life of Mine GHG Emissions Rail Transport CO2e 100-year (MMT/yr)
Black Thunder	South Hilight	2.4	1037	1.6	1.6	3.8	3.7
	North Hilight	5.0	1037	1.6	1.6	7.8	7.8
	West Hilight	7.8	1037	1.6	1.6	12.4	12.3
North Antelope/ Rochelle	South Porcupine	4.3	1121	1.2	1.2	5.1	5.1
	North Porcupine	8.2	1121	1.2	1.2	9.9	9.8
Jacobs Ranch	West Jacobs	28.5	1037	0.5	0.5	13.4	13.3
Total Selected Alternative Rail Emissions =				***7.6***	***7.6***	***52.4***	***52.1***

Table 4.5.9: Wright Area FEIS Selected Alternative minus withdrawn LBA tracts GHG Emissions from Rail Transport

Mine	LBA Tract	Selected Alternative Additional Mine Life (years)	Average Rail distance (miles)	Selected Alternative Annual GHG Emissions Rail Transport CO2e 20-year (MMT/yr)	Selected Alternative Annual GHG Emissions Rail Transport CO2e 100-year (MMT/yr)	Selected Alternative Life of Mine GHG Emissions Rail Transport CO2e 20-year (MMT/yr)	Selected Alternative Life of Mine GHG Emissions Rail Transport CO2e 100-year (MMT/yr)
Black Thunder	South Hilight	2.4	1037	1.6	1.6	3.8	3.7
	North Hilight	5.0	1037	1.6	1.6	7.8	7.8
	West Hilight	0.0	0	0.0	0.0	0.0	0.0
North Antelope/ Rochelle	South Porcupine	4.3	1121	1.2	1.2	5.1	5.1
	North Porcupine	8.2	1121	1.2	1.2	9.9	9.8
Jacobs Ranch	West Jacobs	0.0	0	0.0	0.0	0.0	0.0
Total Selected Alternative minus withdrawns tracts Rail Emissions =				***5.6***	***5.6***	***26.6***	***26.5***

Table 4.5.10: Estimated Actual 2017 GHG Emissions from Rail Transport

Mine	2017 Coal Transport by Rail (million tons/yr)	Estimated Remaining Mine Life (years)	Average Rail Distance (miles)	2017 Annual GHG Emissions from Rail Transport CO_{2eq} 20-year (MMT/yr)	2017 Annual GHG Emissions from Rail Transport CO_{2eq} 100-year (MMT/yr)	2017 Life of Mine GHG Emissions from Rail Transport CO_{2eq} 20-year (MMT)	2017 Life of Mine GHG Emissions from Rail Transport CO_{2eq} 100-year (MMT)
Black Thunder	70.51	10	1,037	0.8	1.6	8.3	15.8
North Antelope/ Rochelle	101.6	10	1,121	1.3	1.2	12.9	12.0
Jacobs Ranch	0	0	1,037	0.0	0.5	0.0	0.0
Total 2017 Rail Emissions =				***2.1***	***3.2***	***21.2***	***27.8***

The Wright Area FEIS also discussed the uncertainty surrounding potential programs, initiatives, and regulations to reduce greenhouse gas emissions and increased energy efficiency at the Federal, state and local levels and how that might affect future CO_2 emissions. The FEIS also elaborated on overall projections of energy-related CO_2 emissions from several *AEOs*.

The Wright Area FEIS discussed that in the *AEO2007*, energy-related CO_2 emissions were projected to grow by about 35 percent from 2006 to 2030 (EIA 2007). By comparison, the *AEO2008* projected energy related CO_2 emissions to grow by 16 percent, from 5,890 MMmt in 2006 to 6,851 MMmt in 2030 (EIA 2008b). However, *AEO2009* projected energy-related CO_2 emissions to grow by 7 percent, from 5,991 MMmt in 2007 to 6,414 MMmt in 2030 (EIA 2009b). The mix of fuel sources for these projections include coal, natural gas, nuclear, liquids (petroleum), hydro-power, and non-hydro renewables (wind, solar, etc.). The lower projected emissions growth rate in the *AEO2009* is due to a slower demand growth combined with increased use of renewables and a declining share of electricity generation that comes from fossil fuels (EIA 2009b). Therefore, at the time of the FEIS analysis and RODs, based upon several *AEO*'s projections which included a projected mix of fuel sources, including renewables, CO_2 emissions were projected to continue to increase through 2030. It was also noted that more rapid improvements in technologies that provide for less CO_2 emissions, new CO_2 mitigation requirements, or an increased rate of voluntary CO_2 emissions reduction programs could result in significantly lower CO_2 emissions levels than were estimated in the FEIS.

Numerous factors influence a utility's decision for best future options for generation and transmission. It has become clear that there has been an increased capacity and use of renewable sources for electricity generation in the past decade. The U.S. wind's market share has increased every year since 2001 in part due to a combination of technology and policy changes (EIA 2016b; Ratner 2017). Numerous states have renewable portfolio standards and there have been several tax credits offered for renewable energy sources (GAO 2015; EIA 2016b; Ratner 2017). While coal plants continue to be retired, it is not expected in the near term for renewable sources to be used regularly as a baseload generation unit (NETL 2018). Due to the variable nature of many renewable sources such as wind and solar, it is difficult for utilities to utilize renewable sources as a baseload unit (GAO 2015; EIA 2017b). Since utilities need to be able to provide a reliable source of electricity to meet demand as demand occurs, the fluctuations in wind and solar generation associated with weather and seasonal changes increases reliability uncertainty (GAO 2015). This can mean that utilities would need to be able to switch to other sources for electricity generation when wind or solar is not available (GAO 2015; NETL 2018).

Energy related CO_2 emissions have declined for 7 of the 10 years in the decade from 2007 to 2017 and were 14% (849 MMmt) lower than 2005 levels in 2017 (EIA 2018c). Energy related CO_2 emissions rose by 2.9% in 2018, however, EIA forecasts that these CO_2 emissions will decline by 1.6% in 2019 and by 0.5% in 2020 (EIA 2019e). The 2018 increase largely reflected increased weather-related natural gas use because of additional heating needs during a colder winter and for higher electric generation to support more summer cooling use than in 2017. EIA expects emissions to fall in 2019 and in 2020 because of forecasted temperatures that will return to near normal and natural gas and renewables making up a higher share of electricity generation. The portion of the projected decrease attributable to coal is between 28 – 87 MMmt per year (EIA 2019e).

Coal has historically been the second largest source of energy related CO_2 emissions since 1990 and coal related CO_2 emissions have been declining since the 2007. Petroleum and other liquids continue to be the largest source of energy related CO_2 emissions. In 2015 natural gas related CO_2 emissions exceeded coal related CO_2 emissions. The natural gas share of electricity generation has generally been growing, while the coal share has been declining. Natural gas CO_2 emissions surpassed those from coal in 2015. However, because natural gas produces more energy for the same amount of emissions as coal, growth in natural gas consumption contributed to the overall 2017 decline in carbon intensity and emissions. CO_2 emission from electricity generation has decreased overall by 28 percent from 2005 to 2017 (EIA 2018c).

Forecasting into the future, *AEO2018* projects that carbon intensity (CO_2 emissions per BTU of energy consumed) will decrease by 9% due to energy efficiency, improved fuel economy, reductions in the consumption of carbon intense fuels, and the use of low or no-carbon fuels. Coal-fired electric generating capacity is projected to decrease through 2030 then levels off through 2050 while coal production generally decreases through 2022 and then levels off through 2050 primarily due to retirements of coal-fired power plants (EIA 2018d). Electric generating related CO_2 emissions are anticipated to remain relatively flat in part due to increased natural gas use and policies supporting renewable sources compared to coal (EIA 2018d). However, different fuel prices, especially for natural gas could increase the use of existing coal-fired generation units for electricity and thus coal related CO_2 emissions (EIA 2018d).

4.6 General Electricity Market and Coal Production Changes Since 2008

There is difficulty in forecasting or projecting what future electricity markets may look like given the various factors that can influence it. EIA specifically states in the *AEO2010* that "[e]nergy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty" (EIA 2010a p. ii). To highlight this difficulty in forecasting, Graphs 4.6.1 and 4.6.2 show the *AEO2010* Reference case total electricity generation projected market shares by fuel source (EIA 2010a) compared to the actual net generation[29] (all sectors) market shares by fuel source (EIA 2018e) from 2008 to 2017. Graph 4.6.1 compares actual net generation and projected generation market shares for natural gas, nuclear, and renewable sources[30] and indicates that there was considerable difference in the market share of natural gas between the projections and actual net generation use. The *AEO2010* Reference case anticipated that the use of natural gas for electricity generation would decrease to a little over 15 percent market share when in fact natural gas increased to being over 30 percent of the electricity generation market share in 2017 (see Graph 4.6.1). The market

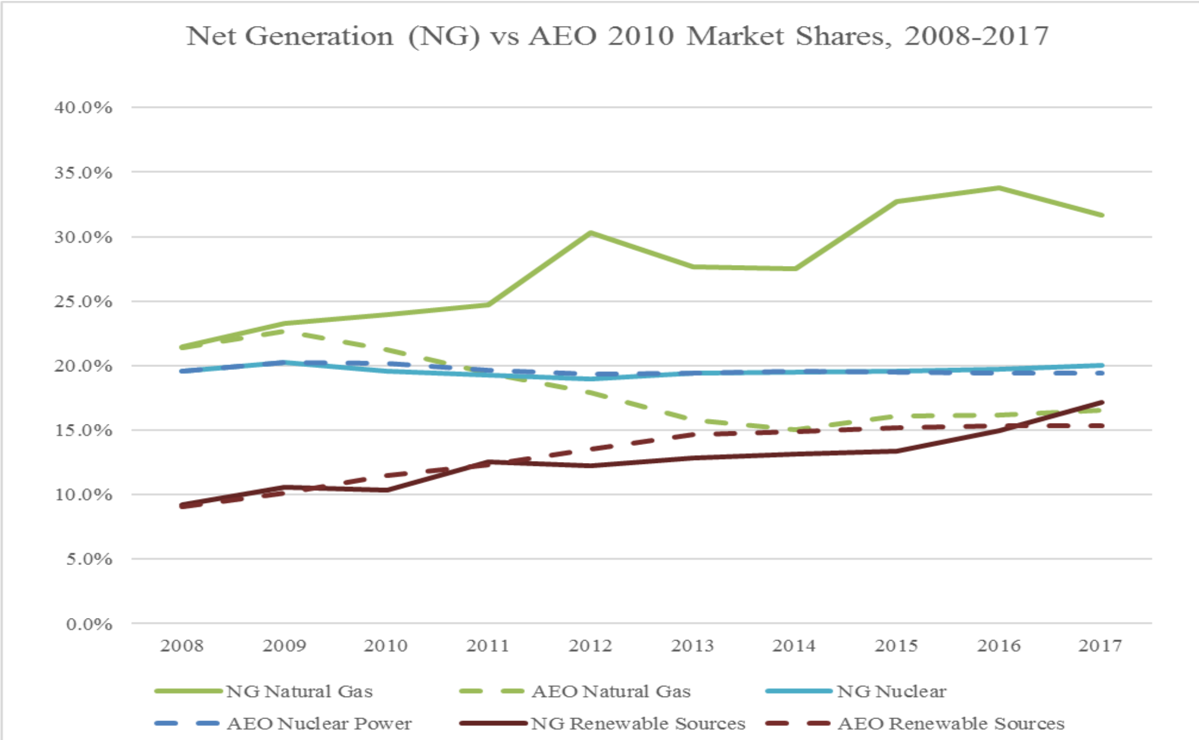
[29] Graphs 4.6.1 and 4.6.2 show *AEO2010* projections for total electricity generation by fuel source and net generation of electricity (all sectors) by fuel source. Net generation excludes the electrical energy consumed by generating stations for services, but still provides a reasonable approximation to compare to *AEO2010* total electricity generation market shares.
[30] Petroleum and "Other" sources were not compared due to the very low use of these sources, as compared to the other fuel sources, for electricity generation (EIA 2018d).

shares of renewable sources for net electricity generation were slightly lower than *AEO2010* Reference case projections from 2012 through 2016 and increased slightly over *AEO2010* Reference case projections in 2017 (see Graph 4.6.1). Nuclear has maintained approximately 20 percent market share of the net electricity generation as projected by *AEO2010* (see Graph 4.6.1).

As indicated by Graph 4.6.2, net electricity generation has seen a considerable reduction in coal market shares going from a little over 48 percent in 2008 to 30 percent in 2017 whereas the *AEO2010* Reference case had projected coal to have approximately 47 percent market share in 2017. The graphs exemplify how the electrical generation markets have changed and differ from what was anticipated.

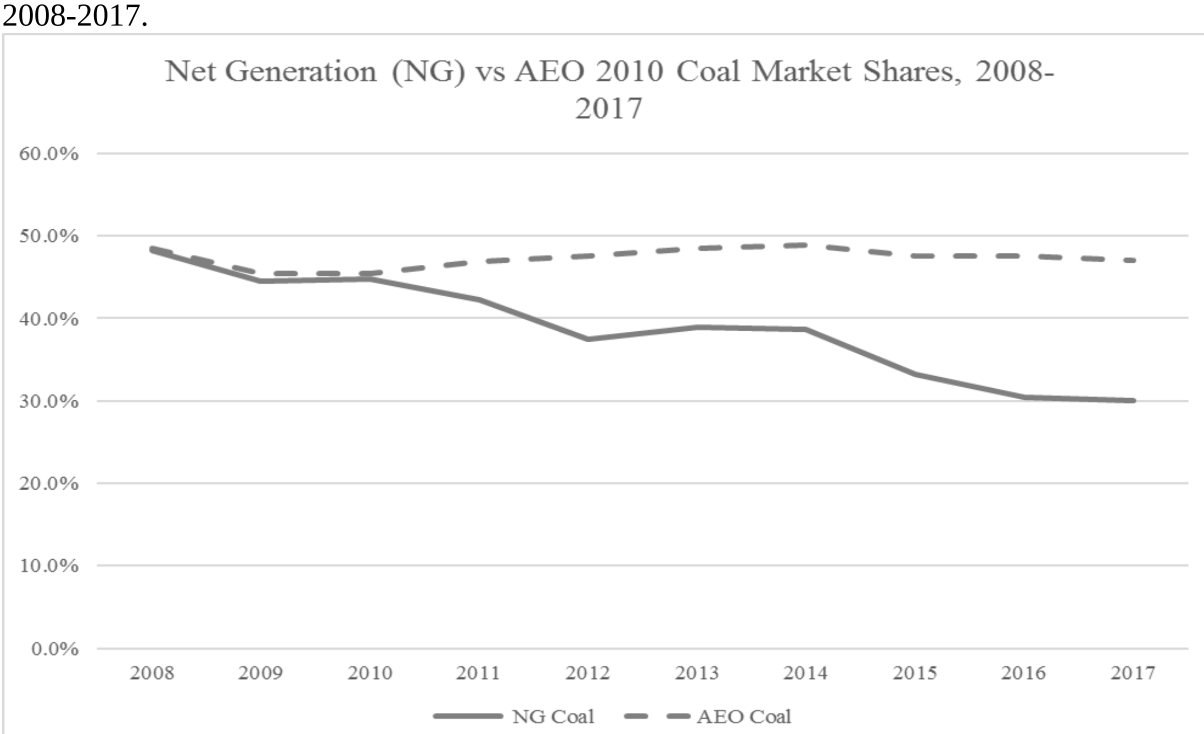
The significant changes within electrical generation markets during the 2008-2017 time-period have occurred due to multiple forces including the economic downturn in 2007 through 2009, the shale gas boom, and growth of renewable sources in the electricity generation market (GAO 2012; Macmillan, Antonyuk, and Schwind 2013; Logan, Medlock, and Boyd 2015; Hibbard et al. 2017; Ratner 2017; Repsher et al. 2018). In particular, the unanticipated increase in shale gas development and production has caused a drop in price of natural gas to a point where it is competitive with coal (Macmillan et al. 2013; Ratner and Glover 2014; GAO 2015; Hibbard et al. 2017; Repsher et al. 2018). As indicated in Graph 4.6.3, the cost per million BTU of natural gas for electricity generation dropped significantly around 2012 which is when the market share of natural gas also saw a big increase (as seen in Graph 4.6.1). Another large increase in natural gas market shares occurred in the 2015-2016 timeframe (as seen in Graph 4.6.1) which is when costs for natural gas decreased to the point of being similar to that of coal (Graph 4.6.3). The increased sustained production of shale gas and the resulting lower prices has caused utility operators to shift power generation from higher cost coal plants to underutilized existing natural gas burning generating units or to install new natural gas units (Liang, Ryvak, Sayeed, and Zhao 2012; Campbell et al. 2013; Hibbard et al. 2017; Repsher et al. 2018). In fact, coal consumption for electricity generation in 2017 was at the lowest level since 1982 (EIA 2018f). This reduced coal consumption is also due, in part, to the retirement of older coal-fired generating units and the lower use of existing operational coal units; however, these plant retirements have had the least effect on PRB coal as opposed to other coal regions (Repsher et al. 2018). "This is because [plants that burn PRB coal] are mostly newer and larger efficient plants and the cost of pollution control is lower for plants using low sulfur coal than for plant[s] using other types (Repsher et al. 2018 p. 16). It should be noted that the sale of three of the four LBAs did not increase coal production nor coal consumption for electricity generation (see Graphs 4.6.2 and 4.6.5).

Graph 4.6.1: Net Generation (All Sectors) vs *AEO2010* Reference Case Market Shares, 2008-2017.



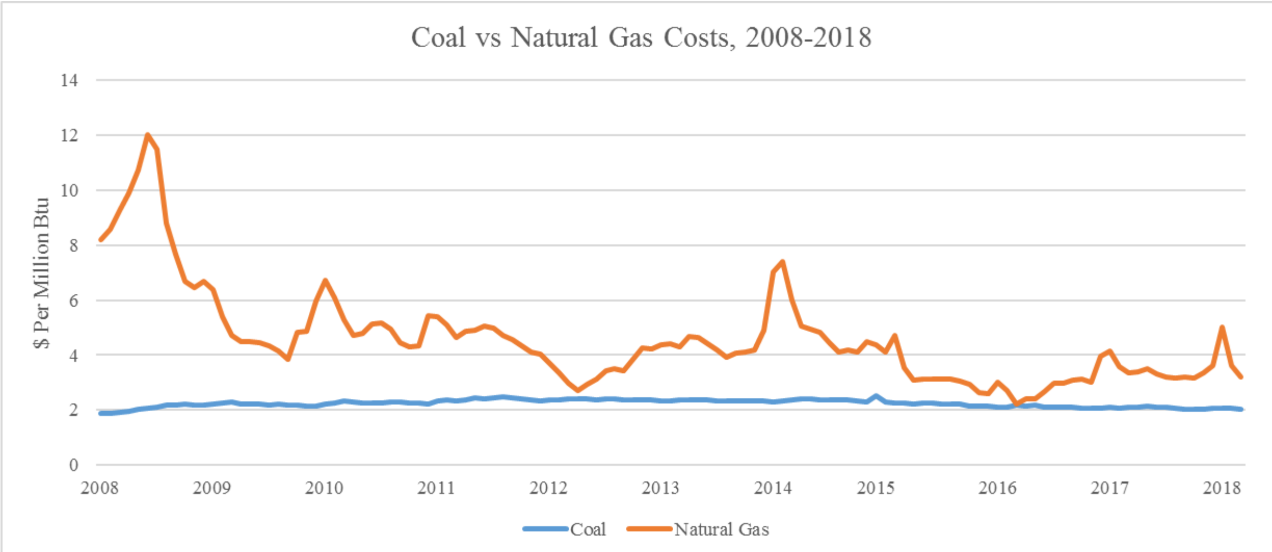
Sources: NG data from EIA 2018e, *AEO2010* data from EIA 2010a.

Graph 4.6.2: Net Generation (All Sectors) vs *AEO2010* Reference Case Coal Market Shares, 2008-2017.



Sources: NG data from EIA 2018e, *AEO2010* data from EIA 2010a.

Graph 4.6.3: Costs of Coal vs Natural Gas for Electricity Generation in Nominal Dollars, 2008-2018



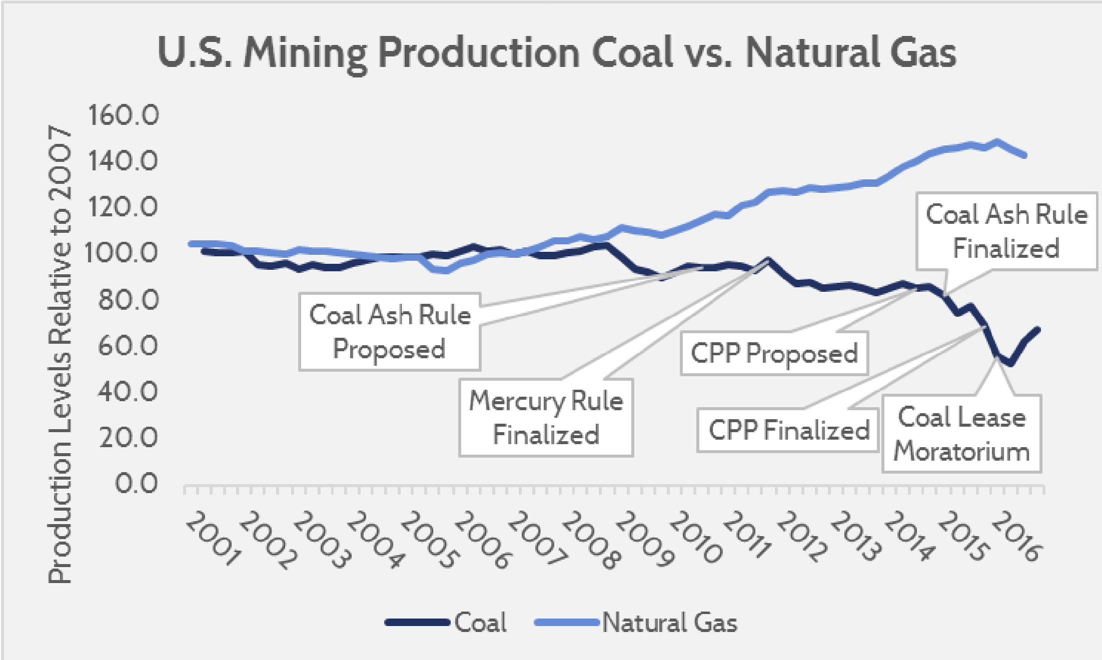
Source: EIA 2018g

Federal regulations since 2008 have also affected coal production and demand as indicated by Graph 4.6.4. For example, EIA in 2014 examined operators' approaches to the Mercury and Air Toxics Rule (Mercury Rule in Graph 4.6.4) for their existing coal-fired plants and found that approximately 64 percent of the plants already had necessary environmental control equipment to comply with the rule and another 6 percent were going to add control equipment (EIA 2014). Approximately 9.5 percent announced plans to retire non-compliant coal-fired plants whereas over 20 percent were undecided as to upgrade/retrofit or retire their coal-fired plants (EIA 2014). Strategies for complying with the Coal Ash Rule and the Clean Power Plan (CPP) Rule could result in operators retiring additional coal-fired plants which could lead to reduced demand for coal if no new coal-fired plants are built to replace them (GAO 2012; Macmillan et al. 2013).

In addition to federal regulations affecting coal use in the electricity market, various states have their own policies and programs to reduce CO_2 emissions that can include expanding renewable sources in utilities' IRPs or emissions caps that would affect utility planning and dispatching of generation units (EPA 2016; Hibbard et al. 2017; Ratner 2017).

Utility companies have dealt with the uncertainty of potential future environmental regulations that could affect their operations and investment planning (Johnston et al. 2007; Barbose et al. 2009). In particular, many utility companies are incorporating carbon regulation and costs scenarios into their long-term planning and several states actually require it as part of their IRP (Johnston et al. 2007; Luckow et al. 2016). However, the various assumptions and cost estimates associated with potential carbon regulations differ greatly among the utilities that have attempted to incorporate carbon regulation scenarios into their long-term planning (Johnston et al. 2007; Barbose et al. 2009).

Graph 4.6.4: Examples of Factors Affecting Coal Demand



Source: https://www.americanactionforum.org/research/coal-declines-markets/

Incorporation of potential carbon regulations, or other greenhouse gas emissions, and the assumptions and cost estimates used by utility companies is important because differing assumptions and costs could influence generation dispatch order as well as potentially earlier retirements of existing coal plants and the resulting additional generation needs.

Overall changes to the electricity market, the shift towards more natural gas use for electricity generation, and concerns over greenhouse gas emissions has had an effect on coal production across the U.S. There has been a downward trend in production levels that mirror the actual use of coal in electricity generation (as displayed in Graph 4.6.2). Since 2008 coal production decreased from over 1170 million short tons produced to approximately 728 million short tons produced in 2016 (Graph 4.6.5). However, the *AEO2010* Reference case forecasted coal production to remain relatively stable with around 1100 million short tons produced annually during this same timeframe (Graph 4.6.5). This helps highlight the difficulty in forecasting fuel sources' market shares in changing electricity markets. Note that in 2011 and 2012 when three of the four leases of interest in this Remand EA were sold by BLM, overall coal production was decreasing in the U.S. (Graph 4.6.5). This indicates that the sale of the three leases did not increase coal production nor coal consumption for electricity generation (see Graphs 4.6.2 and 4.6.5).

Moreover, the leasing of the three tracts by BLM in 2012 appears to have had little impact on the average sale price (FOB) of coal (Graph 4.6.6). While the U.S. (all coal) price (in nominal dollars[31]) in 2012 slightly decreased from $41.01 per short ton in 2011 to $39.95 per short ton,

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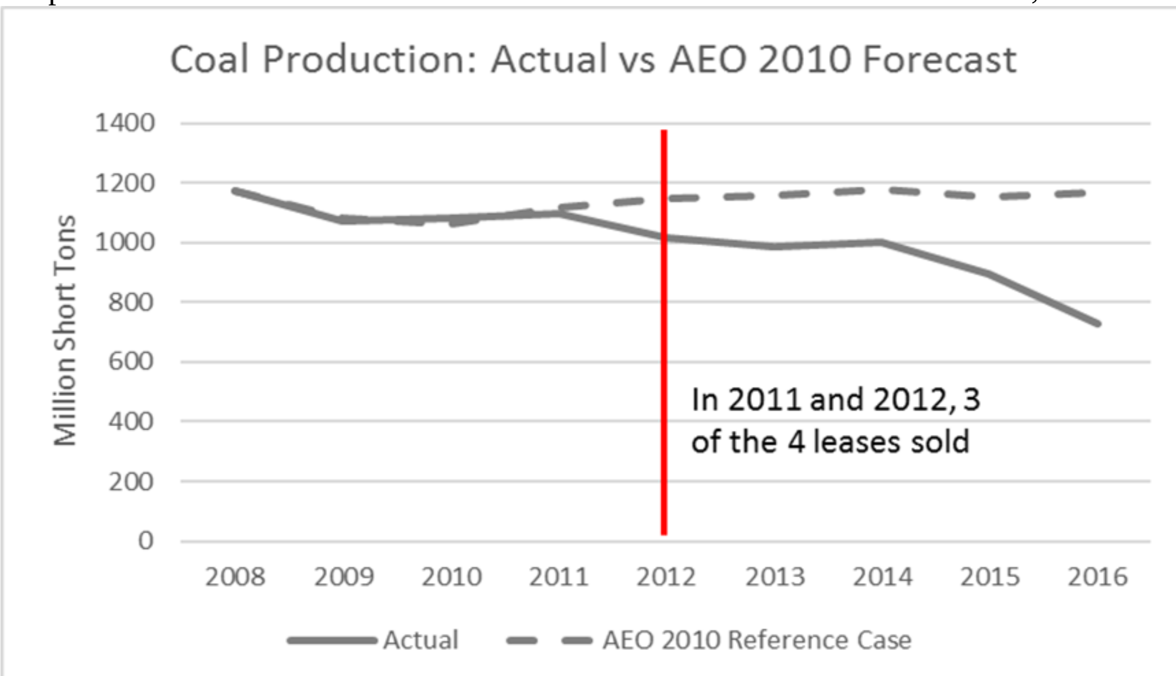
[31] EIA provides the coal prices in nominal dollars which is why nominal dollars is used here. When all costs are adjusted to real (or current) 2017 dollars, by using Bureau of Labor Statistics CPI, similar trends exist.

the Wyoming produced coal price actually increased from $13.56 to $14.24 per short ton in that time period (EIA 2018i).

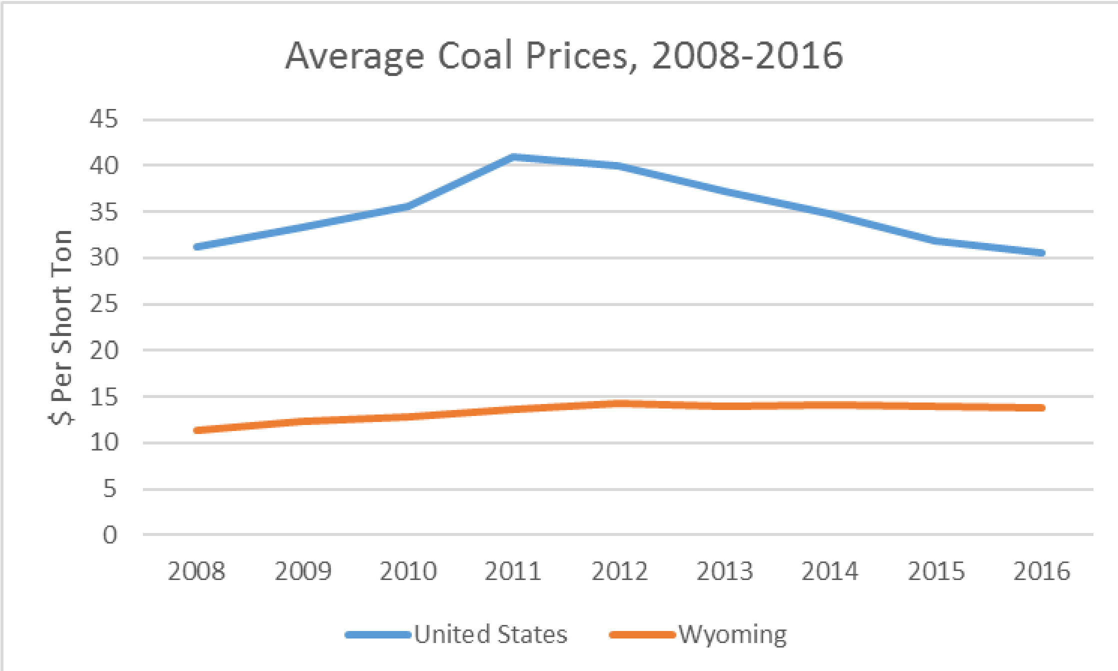
Graph 4.6.5: Actual U.S. Coal Production vs *AEO2010* Reference Case Forecast, 2008-2016



Source: Actual production from EIA 2018h, *AEO2010* data from EIA 2010a.

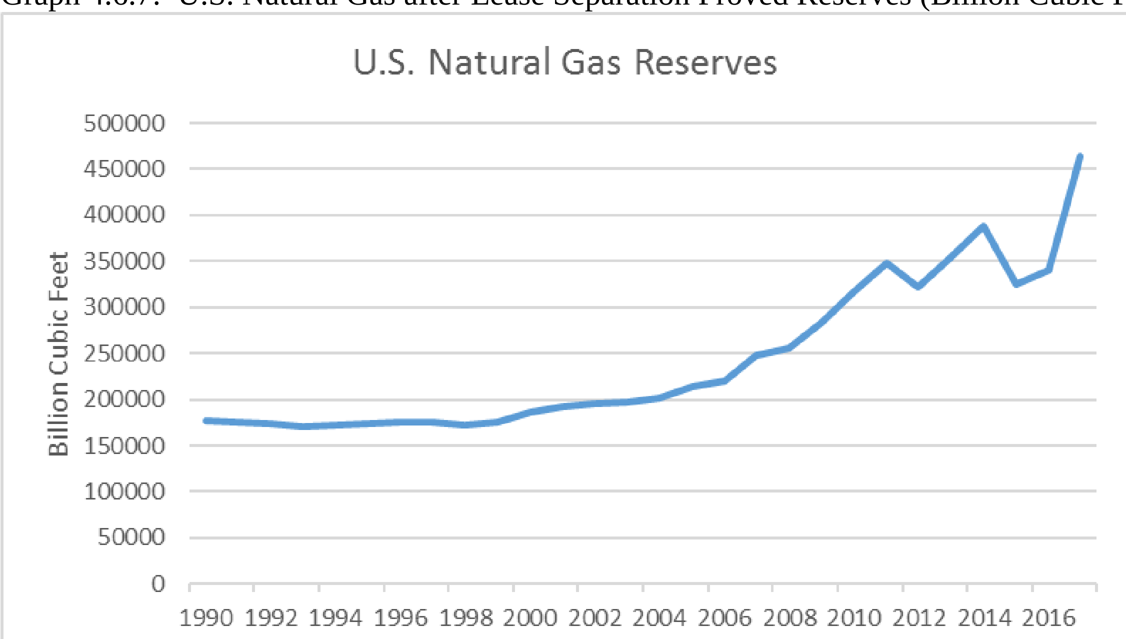
The overall trend for U.S. coal prices from 2011 to 2016 is a continued decline in price (Graph 4.6.6) while coal use for electricity generation also declines (Graph 4.6.2) which supports that coal is own-price inelastic. Prices for Wyoming produced coal tend to remain stable around the $14.00 per short ton from 2013 through 2016 (Graph 4.6.6). The fact that Wyoming coal prices slightly increased after 2011 and then tended to remain stable through 2016 after the sale and leasing of three of the four tracts, counters the idea that leasing the tracts would decrease price and thus increase consumption. This again supports the conclusion that coal is own-price inelastic. The decline in U.S. coal prices reflects decreased coal demand due to availability of natural gas at competitive prices. The key to the competitive gas prices was technological advancements in hydraulic fracturing, which flooded the market with natural gas causing the price of gas to fall lower than was predicted. As seen in Graph 4.6.7, gas production began a rapid increase in 2008 and it continued to grow through 2017, with that year having the largest amount of reserves of over 450 trillion cubic feet. Other factors influencing less electricity demand and, therefore, less coal demand, include more mild weather conditions and energy efficiency contributing to overall less electricity demand (EIA 2013; EIA 2017c; EIA 2018h). Additionally, EIA indicates that compliance with the Mercury and Air Toxics Standards played a role in decreasing net coal capacity, by approximately 60 gigawatts, between 2011 and 2016 (EIA 2018d).

Graph 4.6.6: Average Coal Price for U.S. (All Coal) and Wyoming Produced Coal in Nominal Dollars, 2008-2016



Source: EIA 2018i.

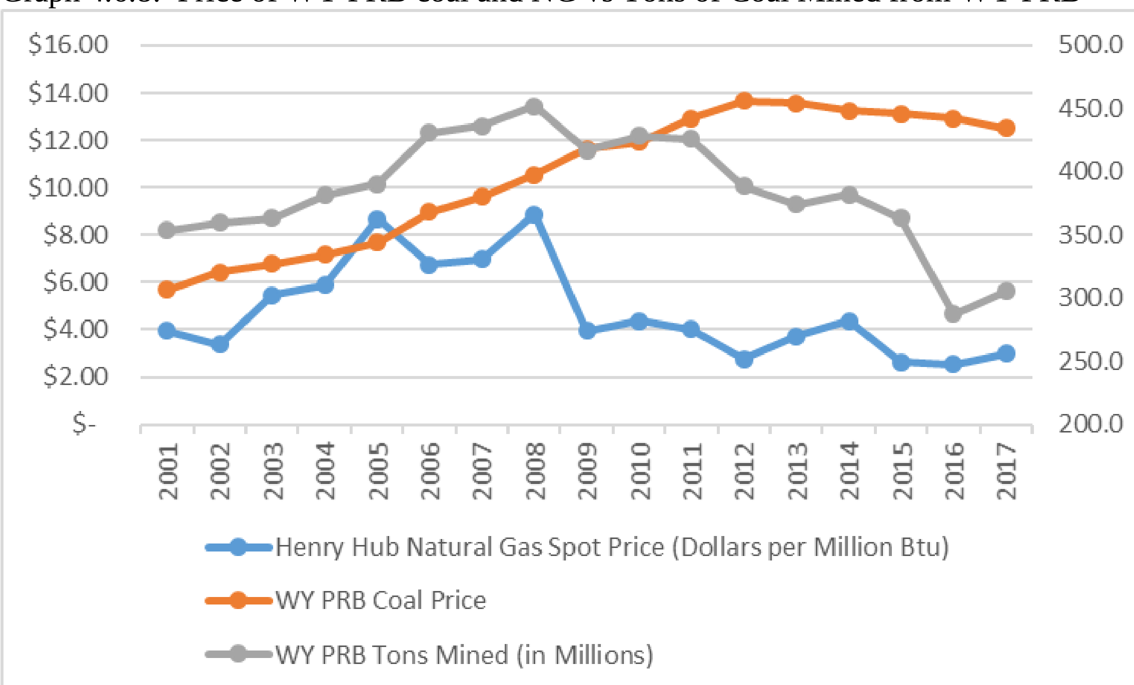
Graph 4.6.7: U.S. Natural Gas after Lease Separation Proved Reserves (Billion Cubic Feet)



Source: https://www.eia.gov/dnav/ng/hist/rngr21nus_1a.htm

This amount of gas and the resulting drastic reduction of the price of gas has a much larger effect on the market than the potential leasing of the four LBA tracts and is one of the major reasons for the decrease in coal production after 2008. Graph 4.6.8 illustrates the amount of coal mined continued to rise through the early 2000s even as the price of WY PRB coal rose. However, when the price of gas fell dramatically in 2009 and was competitive with coal prices, coal production dropped. Coal production dropped even further in 2015 as gas prices hit a new low and production has remained at or near this reduced level even as the price of WY PRB coal has remained relatively flat. This indicates that more recently that coal demand became cross-price elastic in regards to natural gas (Repsher et al. 2018), which is different from previous studies as discussed in Section 4.4.2

Graph 4.6.8: Price of WY PRB coal and NG vs Tons of Coal Mined from WY PRB



Source: EIA2018g,h

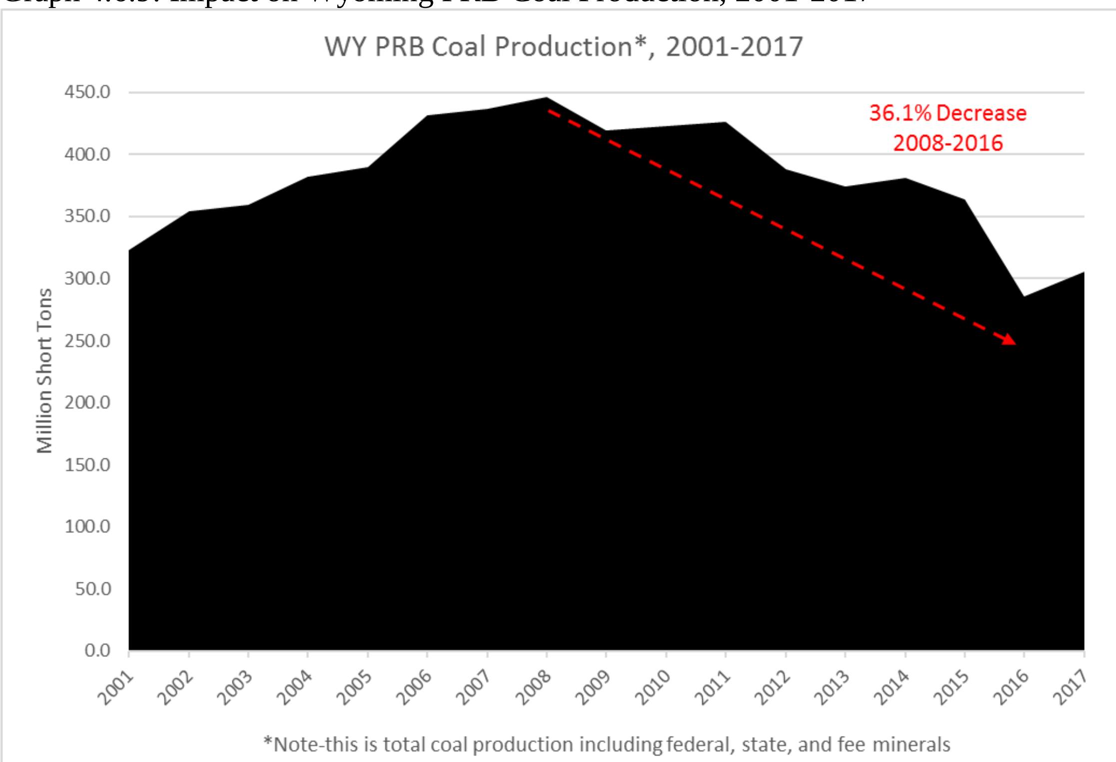
With a reduction in coal demand there was also a decrease in the percent of federally-administered coal produced out of total U.S. production. The percent of federally-administered coal produced (sales volume), not including coal produced from American Indian lands, was 42.8 percent of total U.S. production in fiscal year 2010 and lowered to 40.8 percent by fiscal year 2014[32] (EIA 2015).

Shifts within the electricity market and overall coal production have also affected coal production in the Wyoming portion of the PRB. For example, the Mercury and Air Toxics Rule discussed previously has "required significant improvements in emission reduction equipment to be installed at many plants and these new installations have undermined the need to burn PRB coal to take advantage of its low-sulfur content. Competitors such as Illinois Basin coals have

[32] Data for fiscal year 2014 is the latest data available from the EIA that provides a breakdown of fossil fuel sales of production from federal lands (EIA 2015).

higher heat and lower moisture contents relative to PRB coal and the combination of some of the lowest production costs; better fuel characteristics; reduced shipping costs; and the reduced need for low-sulfur fuels has allowed these challengers to gain advantages in some Midwestern, Mid-Atlantic and Southeastern markets" (Godby, Coupal, Taylor, and Considine 2015 p.32). Additionally, issues associated with railroad congestion and transportation costs have impacted the ability to get Wyoming PRB coal to markets, and the need to mine deeper WY PRB coal deposits has reduced production (National Research Council 2007; Godby et al. 2015). Graph 4.6.9 highlights a 36.1 percent decrease in Wyoming PRB coal production 2008 to 2016, with a slight uptick in production in 2017, but still considerably lower than 2008 production levels.

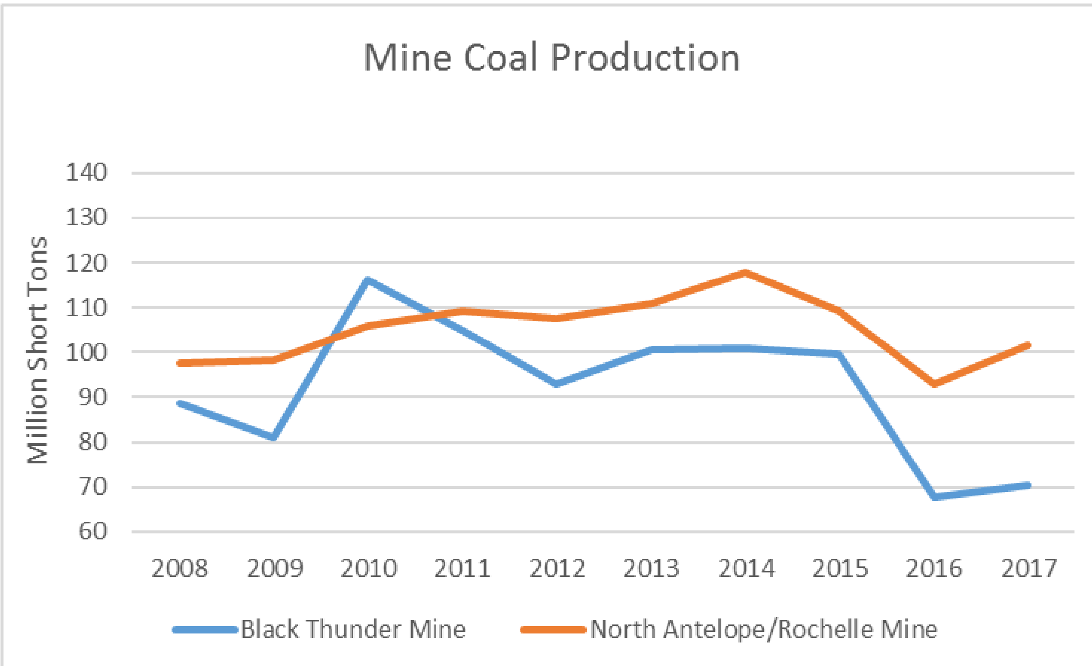
Graph 4.6.9: Impact on Wyoming PRB Coal Production, 2001-2017



Source: U.S. BLM High Plains District Office 2018

As previously mentioned, the three leased tracts of interest in this Remand EA, South Hilight Field purchased by the Black Thunder Mine and the South Porcupine and North Porcupine tracts purchased by the NARO Mine, were approved for mining in 2013 and 2014 by WDEQ and mining is underway and ongoing at all three tracts. Approval of these tracts has not caused an increase in production since 2014 and in fact both mines have seen decreased production amounts as indicated by Graph 4.6.10. There has been variation in the amount of coal produced at the Black Thunder Mine and the NARO Mine from 2008 to 2017 (see Graph 4.6.10). Although the Black Thunder Mine is permitted to produce 190 million short tons of coal per year, the most that the mine has produced during the 2008 to 2017 time period is 116.2 million short tons in 2010 and significantly reduced production to 67.9 million short tons in 2016 as indicated by Graph 4.6.10 (MSHA 2018a). The large increase in production from 2008 and 2009 compared to 2010 is due to Black Thunder acquiring the Jacobs Ranch Mine and the additional production from there. Graph 4.6.10 also indicates that the NARO Mine slowly increased production from 2008 and production peaked in 2014 at approximately 118 million short tons which is still lower than the 140 million short tons that the mine is permitted to produce per year. The NARO Mine also reduced production in 2016 to only about 92.9 million short tons (MSHA 2018b). Although both mines saw increased production levels in 2017, production levels are still lower than their permitted amounts by 62.9 percent (Black Thunder Mine) and 27.4 percent (NARO Mine) (MSHA 2018a,b).

Graph 4.6.10: Black Thunder Mine and North Antelope/Rochelle Mine Coal Production, 2008 to 2017



Source: MSHA 2018a,b.

The North Hilight Field tract remains unsold, but if leased could contribute to meeting future coal demands. The EIA anticipates that U.S. coal demand will likely remain relatively flat through 2050 averaging only 750 million short tons per year with at least 25 gigawatts of coal-fired capacity being retired between 2018 and 2020 (EIA 2018j). Coal production is forecasted to decrease until 2022 and then slightly rise until 2030 and then stabilize through 2050 (EIA 2018d). Not leasing the North Hilight Field tract does not mean coal consumption by the electric power sector would be reduced since so many other factors, as discussed throughout this Remand EA, contribute to the fuel sources used for electricity generation and the demand for electricity.

4.7 Conclusion

The theory of supply and demand suggests that the Wright Area FEIS No Action Alternative represents a decrease in the supply of coal that would lead to an increase in price. Alternatively, this theory suggests the Wright Area FEIS Selected Alternative represents an increase in supply that leads to a decrease in price. In short, the supply and demand model predicts that the Wright Area FEIS No Action Alternative leads to less coal leased and a higher price for coal than the

Selected Alternative. However, the theory of supply and demand provides an overly-simplistic and inaccurate model for predicting changes in coal pricing and demand within the electric power system. While it is true that under the law of demand, a decrease in the price of a normal good will cause an increase in quantity demanded, the responsiveness of quantity demand relative to a change in price is more nuanced (own-price elasticity) and depends upon numerous factors such as the availability of substitutes, length of adjustment period and the budget share spent on the good. In the case of electric power generation, historically the consumption of coal was generally unresponsive to prices (inelastic). In regards to fuel substitution and fuel substitution elasticities, research by Dahl and Ko 1998; Ko and Dahl 2001; Tuthill 2008 indicate coal was generally price inelastic, meaning that coal, oil, and natural gas prices for electric power generation would likely not cause significant changes in the use of/demand for coal. However, more recently the considerable drop in natural gas prices have decreased coal use in the electric power system.

As discussed in this Remand EA, the reality of electric power systems is more complicated than the simple supply and demand model. Even in the states and regions that have moved forward with a market approach, "a large number of nonmarket mechanisms have been imposed on emerging competitive wholesale and retail markets. These mechanisms include spot market price caps, operating reserve requirements, non-price rationing protocols, and administrative protocols for managing system emergencies" (Joskow and Tirole 2004 p. 1). These nonmarket mechanisms and price controls act to dampen or distort consumer reactions to potentially important market signals (Brown et al. 2017), and thereby render the theory of supply and demand an ineffective model for coal demand and/or pricing within the electric power system.

Overall, the information in the Remand EA indicates that the *AEO2010* cases (scenarios) reviewed show that coal's market share of electric generation is anticipated to decrease in the future. However, coal was still projected to comprise the largest market share of total electricity generation in 2025 and 2035 under all five cases reviewed (see Tables 4.4.2 and 4.4.3) even though the cases do indicate that coal costs can have a slight effect on fuel source decisions (EIA 2010a). Coal production is projected to continue with over 1,000 million short tons being produced each year for all five cases to meet the demand from the electric power sector (EIA 2010a). Based upon the 2008 USGS study and coal amounts already permitted and in the LBA process, not only did the mines have approximately 10 years of permitted coal to continue mining, but there were also ample reserves of coal with the same rank and qualities available for leasing in the WY PRB to supply demand in the event the subject four LBA tracts were not leased (the Wright Area FEIS No Action Alternative). The leasing program in the PRB strives to make coal available for lease to meet demand; selecting the Wright Area FEIS No Action Alternative would not prevent future leasing. In other words, the Wright Area FEIS No Action Alternative would not limit supply nor would the Wright Area FEIS Selected Alternative "dump" a large supply of coal on the market. In fact, three of the four tracts were leased and are currently being mined and overall coal production and coal use (demand) in electricity generation has decreased. In the short run, there would be no change to the supply of coal in the PRB under the Wright Area FEIS No Action Alternative because all the coal mines had approximately 10 years' worth of permitted supply and in the long run the coal mines in the PRB would have 10 years or more to lease other coal if demand warrants it as there is plenty of coal with similar characteristics available in the PRB.

In examining the analysis in this Remand EA, the possibility exists that some coal could be replaced by another fuel source due to competition. However, the switch from coal to other forms of electricity generation is based on many factors including the cost of the fuel, existing infrastructure, including transmission capabilities (capital), the electric power market structure, and the regulatory environment. The above analysis shows that selection of the Wright Area FEIS No Action Alternative would not have an impact of any significance on electricity generation markets, on decisions to switch to non-coal fuel sources, nor on electricity demand.

Through this environmental review process, the BLM has found that no additional significant effects would occur beyond those already identified in the Wright Area FEIS and associated RODs. Therefore, the BLM has determined that further analysis is not warranted and the decisions in the existing RODs continue to be valid.

Chapter 5

Consultation and Coordination

Table 5-1. Project Contributors and Reviewers

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Chapter 6

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Appendix A

National Energy Modeling System (NEMS)

Housed under the Department of Energy, the U.S. Energy Information Administration (EIA) is the principal agency responsible for collecting, analyzing, and disseminating energy information to promote sound policymaking, efficient markets, and public understanding of energy, energy markets, and environmental interactions (EIA 2018a). EIA programs cover data on energy sources such as coal, petroleum, natural gas, renewable and alternative fuels, and nuclear energy; energy uses such as electricity, consumption and efficiency; and energy flows (EIA 2018a). EIA provides impartial energy information that is used by federal, state, and local governments, the academic and research communities, as well as by businesses and industry organizations (EIA 2018b). It is a requirement that EIA remain policy-neutral (EIA 2009).

As part of its *Annual Energy Outlook* publication, EIA[33] designed and implemented the National Energy Modeling System (NEMS). NEMS is an inter-regional, inter-sectoral, dynamic model using economic, geological, demographic, and other inputs' trends, and assumptions to provide statistical projections related to U.S. energy markets. Specifically, NEMS "projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics" (EIA 2009, p.1). The value of NEMS is that it can provide a consistent framework for numerous complex interactions to evaluate potential responses to differing policies or public initiatives (EIA 2009). The primary use for NEMS is to produce the *Annual Energy Outlook (AEO)*, a yearly EIA publication that is posted publicly to their website. NEMS is also used for special requests related to large-scale scenario analyses, primarily from the U.S. Congress.

As noted in the Remand EA, the BLM relied upon the *Annual Energy Outlook 2010* (*AEO2010*) for understanding what potential electricity demands and generation needs may be through 2035. *AEO2010* included the Reference case, which is the "business-as-usual trend estimate, given known technology and technological and demographic trends" (EIA 2010a p. ii) as well as 38 sensitivity cases[34] or scenarios, five of which were discussed in the Remand EA[35] (EIA 2010a). The *AEO2010* published NEMS projections over a 25-year time horizon, a period in which the economic structure and nature of energy markets can be sufficiently understood with regional

[33] NEMS was developed and is maintained by the Office of Integrated Analysis and Forecasting (OIAF) of EIA (EIA 2010a).
[34] A brief description of the various *AEO2010* cases is provided in Table E1 of EIA 2010a and Table 1.1 in EIA 2010b.
[35] The Remand EA explicitly discussed the *AEO2010* Reference case, the Low Economic Growth case, the High Economic Growth case, the Low Coal Cost case, and the High Coal Cost case.

detail (EIA 2010b). *AEO2010* results are based upon a version of NEMS that represented current legislation and environmental regulations as of October 31, 2009[36] (EIA 2010a,b).

The NEMS model consists of 12 component modules which represent different fuel supplies, end-use consumption, conversion sectors, macroeconomic factors, and international factors as well as an integrating module that executes each of the component modules (see Figure 1). The modular nature of NEMS allows for sector specific assumptions, methodologies and details to be incorporated as well as for revisions to and testing of modules individually. Each component module incorporates the effects, including costs, of legislation and environmental regulations that affect that specific sector or module and accounts for SO_2, NO_x, and mercury associated with electricity generation and combustion related CO_2 emissions (EIA 2010a). Essentially, NEMS, through the modules, balances out energy supply and demand for each fuel source and consuming sector while accounting for competition between differing fuels and fuel supplies on an annual basis (EIA 2010b,e).

Due to differences in energy supply, demand, and conversion factors across the United States, NEMS takes a regional approach to reflect regional differences in energy markets and transportation flows (EIA 2010b). The level of regional detail depends on the specific modules. For the end-use demand modules the regional level is the nine U.S. Census divisions, the North American Electric Reliability Council (NERC) regions and subregions for electricity, the Petroleum Administration for Defense Districts (PADDs) for refineries, and production and consumption regions specific to oil, natural gas, and coal supply and distribution[37](EIA 2010a,b). Given the interactions between modules, *AEO2010* provides most results for the nation, the aggregated nine U.S. Census divisions and/or the NERC regions and subregions, depending on the specific sector and results being evaluated.

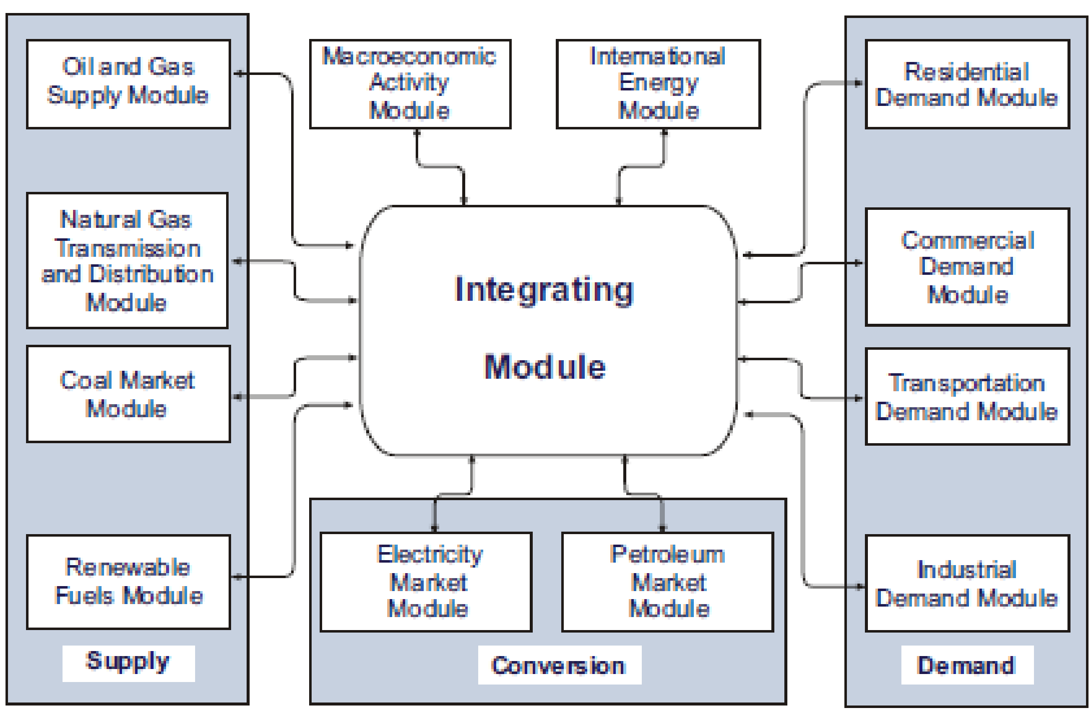
Most modules have several submodules which encompass different key functional areas. For example, the Coal Market Module (CMM) which provides annual forecasts of prices, production, and consumption of coal, is comprised of the Coal Production Submodule (CPS) for coal production, and the Coal Distribution Submodule (CDS) for both domestic coal distribution and international coal trade (EIA 2010c). For the *AEO2010*, there were 14 identified U.S. coal supply regions represented in the CPS and 16 domestic coal demand regions in the CDS[38] (EIA 2010c). The coal of the different supply regions is categorized by four thermal grades (corresponding to coal grades/ranks), three sulfur emissions grades, and mining type (EIA 2010c). The CMM also incorporates environmental-, technological-, and transportation-related constraints that combine to produce a distribution pattern "which differs from unconstrained delivered cost minimization[39]" (EIA 2010c, p.71). Although this is a very simplistic depiction of

[36] Appendix A of EIA 2010b provides information on the handling of Federal and selected State legislation and regulation in *AEO2010*.
[37] Specific regional maps are provided in Appendix F of EIA 2010a. Additionally, Table 2 of EIA 2010e also provides a summary of NEMS modeling detail for the various energy sectors including the applicable regions.
[38] The CDS also includes 17 geographic exporting regions (5 of which are in the U.S.) and 20 importing regions (4 of which are in the U.S.) (EIA 2010c). Note that the CDS projects "U.S. imports required to satisfy coal demand in the U.S. established by the industrial and electricity models" (EIA 2010c, p. 146).
[39] EIA 2010c further elaborates on this by stating, "[e]nvironmental regulation and technological inflexibility combine to restrict the types of coal that can be used economically to meet many coal demands, thus reducing the consumer's range of choice. Supply reliability and local limits on transportation competition combine to restrict

the CMM, it is meant to help demonstrate that EIA has given considerable thought and foresight into the numerous interacting factors that influence the U.S. coal market and its supply, transportation, and consumption components. These interacting factors include the specific type and emission specific information associated with Wyoming Powder River Basin coal production, mine labor productivity, and transportation related costs (for more specific information on the NEMS CMM, please review EIA 2010c).

However, the CMM does not take into account coal stock builds and drawdowns at power plants and mines, because it integrates the NEMS assumption that the "supply and demand for all fuels will balance for all projection years" (EIA 2008, p. 3). This led to underestimations of coal production for specific years in several *AEO*s through 2008 (EIA 2008). Additionally, NEMS Reference case projections over the mid-to-long-term assume a number of current energy market parameters projected into the future, when they may be subject to change. While this is useful for understanding the interaction and general relationship between different variables under certain assumptions, it does not account for the potentially disruptive impact of unanticipated changes affecting energy markets. As a result, observed levels of U.S. steam coal consumption have been less than what previous versions of the *AEO* have projected. This is due to the unforeseen drop in electricity demand that occurred during the recession of 2007-2009, or the unforeseen technological improvements that have led to increased U.S. natural gas production during the shale boom (EIA 2017).

Figure 1. National Energy Modeling System



Source: EIA 2010b p. 2

where, in what quantity, and for how long a technically and environmentally acceptable coal may be available" (p. 71).

The other module of interest for this Remand EA is the Electricity Market Module (EMM) which reflects “the capacity planning, generation, transmission, and pricing of electricity, subject to: delivered prices for coal, petroleum products, natural gas, and biomass; the cost of centralized generation facilities; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand” (EIA 2010d p.7). The EMM contains four interacting submodules— Electricity Load and Demand (ELD), Electricity Capacity Planning (ECP), Electricity Fuel Dispatch (EFD), and Electricity Finance and Pricing (EFP)[40] (EIA 2010d). As was discussed in the Remand EA, electric utility markets are quite complex with a myriad of factors playing a role in capacity planning and fuel use decisions. The EMM has incorporated most of these factors[41]. Essentially, through NEMS and the EMM, EIA attempts to represent potential decision-making by electric utilities given current and projected generation capacity, technological advancements, fuel source supplies and transportation, electricity transmission, and environmental regulations.

Some of the data and information incorporated into the EMM include data on existing electricity generation capacity by fuel source, known and anticipated coal and nuclear plant retirements, electricity generation construction costs, operation and maintenance costs, new technologies, and renewable energy capacity related to State renewable portfolio standard (RPS) mandates or similar laws as integrated into the Renewable Fuels Module (RFM) (EIA 2010d). It should be noted that although the EMM incorporates State-level RPS, the EMM is divided into multi-state regions and therefore is not a state-level model. The EMM must thus approximate State-level compliance based upon this regional breakout (EIA 2010a). Although the RFM is a separate module from EMM, there are considerable interactions between the two modules, which “must be run together” (EIA 2010f p. 7). Some of the inputs to the EMM from the RFM include the existing capacity of renewable energy, location, generating size, operational and maintenance costs, and cost and time of construction of new renewable capacity (for more specific information on the NEMS RFM, please review EIA 2010f).

There are also numerous interactions between the CMM and the EMM. Specifically, the “CDS [a submodule of CMM] provides detailed input information to the EMM including coal contracts, coal diversity information (subbituminous and lignite coal constraints), transportation rates, and coal supply curves. The EMM uses this information to develop expectations about future coal prices and coal availability and allows the EMM to make improved coal planning decisions” (EIA 2010c, p. 69). Furthermore, the EFD submodule of the EMM incorporates environmental considerations, like emission restrictions for SO_2, NO_x, and mercury. The EMM allocates fuel dispatching at minimum cost while considering these restrictions, in addition to engineering constraints. Therefore, the EFD interacts with the CMM in order to “consider the rank of the coal and sulfur and mercury contents of the fuel used when determining the optimal dispatch. In that way the EFD and CMM can more easily achieve convergence to the optimal coal consumption” (EIA 2010d p. 109). Unlike SO_2 and mercury emissions, NO_x emissions depend

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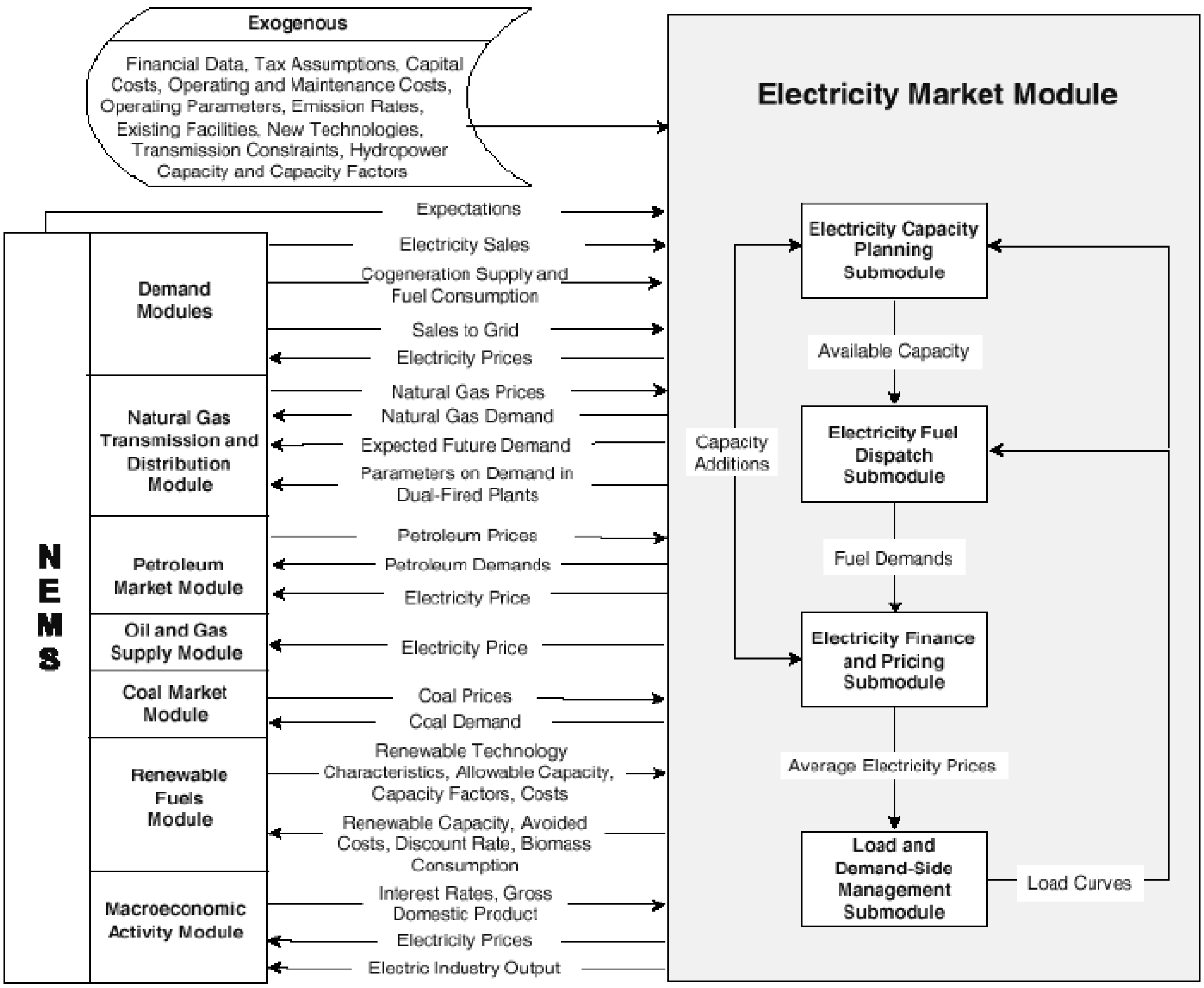
[40] Furthermore, the “solution to the submodules of the EMM is simultaneous in that, directly or indirectly, the solution for each submodule depends on the solution to every other submodule” (EIA 2010d p. 7).

[41] Not all factors that play a role in utility decision-making can be anticipated, nor can potential future technological developments, electricity use/demand, and potential legislation be known. However, *AEO2010* didn’t necessarily ignore these “unknowns” but instead provided projections through the various “sensitivity cases.”

on power plant design and not coal type (EIA 2010d). Figure 2 helps convey the complexity involved within the EMM as discussed above and its interrelated nature to other NEMS modules.

Figure 2. Electricity Market Module Structure



Source: EIA 2010d, p. 10

Constraints for Using NEMS for a BLM Coal Lease Project

NEMS is a high level, complex model designed for large scale (national or regional) use for examining the components of the U.S. energy system and the various interactions between energy, economics, and the environment for the mid- and long-term futures (EIA 2010c). Although the EIA makes the NEMS available for non-EIA entities to use, it does not include the parts of the model that are linked to expensive proprietary software and data unless licenses to those sources are obtained (EIA 2009, 2018c). Additionally, the EIA (2018c) notes that "[m]ost people who have requested NEMS in the past have found out that it was too difficult or rigid to use" (p.1). EIA (2018d) indicated to BLM that mostly large institutions have attempted to run the complex NEMS model, including:

- Booz Allen Hamilton, which used NEMS as a contractor for the DOE's for the National Renewable Energy Laboratory (NREL);
- The Electric Power Research Institute;
- OnLocation, Inc, which contracts with EIA on NEMS and applies NEMS in its energy consulting work, including several DOE program offices and labs;
- Rhodium Group, which uses NEMS to produce private studies and in work for clients including the DOE Office of Policy and International Affairs;
- Leidos (SAIC), which contracts with EIA on NEMS and applies NEMS to work with a number of clients, including the Canadian government, and energy trade associations such as the National Gas Council; and,
- The Union of Concerned Scientists, which has applied NEMS for energy and environmental policy analysis.

Some of the NEMS modules or components of those modules can run individually, without the need for inputs from interactions with other modules (EIA 2018c). However, the Coal Market Module (CMM) is not one of these modules, since it requires data inputs from multiple other modules and EIA designed it to interact with the Integrating NEMS module (EIA 2010c).

NEMS, as complex as it is, has limitations if used by the BLM for a specific coal leasing project in its current state. Although EIA provides brief instructions for running NEMS, given the complexity of the programming and structure of NEMS, potential modifications would likely require EIA to make them, however, "EIA does not have a budget to support the outside use of NEMS" (EIA 2018c p. 4). Additionally, given the national and regional scale of the various components of the modules, it would be difficult to approximate the more localized effects for a specific coal lease since the Coal Production Submodule (CPS) does not disaggregate its 14 supply regions into smaller areas or leases. Moreover, a potentially greater limitation of NEMS for use by the BLM is that NEMS does not distinguish between federally-administered coal versus state administered and private coal leases (Krupnick, Ratledge and Zachary 2016). As such, NEMS would not account for potential substitution of state or private coal in the energy markets and associated emissions if federally-administered coal goes unleased (Krupnick, Ratledge and Zachary 2016). Without the EIA specialists for each module modifying and running the model[42], NEMS is too cumbersome and costly for the BLM to run on its own for smaller individual coal leasing projects[43].

However, even though the BLM did not run the NEMS model for this specific coal leasing project, NEMS results were considered. The EIA based its *AEO2010* projections on NEMS results that reflected what might happen given the various assumptions and methodologies used for each scenario or case (EIA 2010a). The *AEO2010* projections for the various cases examined fuel supplies, location and transport of fuels, the potential for increased renewable generation, electricity demand and existing and projected generation capacity, transmission factors and fuel

[42] NEMS generally requires two to three EIA specialists to run each module for *AEO* projections.
[43] Krupnick, Ratledge and Zachary 2016 further expand on the complexities of NEMS by saying the "comprehensiveness [of NEMS] comes at the cost of having outputs that can be hard to interpret…[m]oreover, NEMS's comprehensiveness and complexity often mean that changes to one part of the model necessitate changes to other parts, presenting coordination challenges and contributing to further delays" (p. 7). This further supports BLM's assertion of NEMS being too cumbersome and costly to run for individual coal leasing projects.

dispatching decisions for electricity generation and the potential for fuel switching in existing plants. The BLM did not focus solely on the *AEO2010* Reference case. Rather, the BLM evaluated the range of cases analyzed and discussed the five cases that were thought to be most relevant to the Remand EA. Additionally, the EIA compares the *AEO2010* Reference case to projections produced by other organizations and entities which allows for a broader perspective on what future energy markets may look like (EIA 2010a) which the BLM also considered.

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Appendix B

Justification for Not Calculating a Social Cost of Carbon Estimate

A protocol to estimate what is referenced as the "social cost of carbon" (SCC) associated with greenhouse gas (GHG) emissions was developed by a federal Interagency Working Group on Social Cost of Carbon[44] (IWG). SCC was developed to assist agencies in addressing Executive Order (E.O.) 12866, which requires federal agencies to assess the cost and the benefits of proposed regulations as part of their regulatory impact analyses. The SCC is an estimate of the economic damages associated with an increase in carbon dioxide emissions and is intended to be used as part of an economic cost-benefit analysis for proposed rules. As explained in the Executive Summary of the 2010 SCC Technical Support Document "[t]he purpose of the [SCC] estimates…is to allow agencies to incorporate the social benefits of reducing carbon dioxide (CO2) emissions into cost-benefit analyses of regulatory actions that have small, or 'marginal,' impacts on cumulative global emissions" (IWG 2010, p. 1). While the SCC protocol was created to meet the requirements for regulatory impact analyses during rulemakings, BLM has received requests to expand the use of SCC estimates to project-level National Environmental Policy Act (NEPA) analyses.

The decision was made not to expand the use of the SCC protocol for the coal leasing actions discussed in the Remand EA[45] for a number of reasons. First, NEPA does not require an economic cost-benefit analysis (40 C.F.R. § 1502.23), although NEPA does require consideration of "effects" that include "economic" and "social" effects (40 C.F.R. 1508.8(b)). The economic analysis in the Wright Area FEIS was a regional economic impact analysis utilizing input-output modeling. Regional economic impact analyses describe effects that agency activities may have on economic conditions and local economic activity, generally expressed as projected changes in employment, labor income, and economic output (Watson, Wilson, Thilmany, and Winter 2007). An economic cost-benefit analysis, on the other hand, is an approach used to determine economic efficiency by focusing on changes in social welfare by comparing whether the monetary benefits gained by people from an action/policy are sufficient in order to compensate those made worse off and still achieve net benefits (Watson et al. 2007, Kotchen 2011). A cost-benefit analysis requires the identification and valuation of all the costs and benefits associated with an action/policy in a common monetary measure and is often expressed either as net benefits or as a cost-benefit ratio, which indicates the value of benefits

[44] The IWG was later renamed the Interagency Working Group on Social Cost of Greenhouse Gases.

[45] The climate change discussion in the Remand EA is based upon the analyses and discussions in the Wright Area FEIS. Therefore the discussion in this appendix focuses on how this Remand EA and the Wright Area FEIS analyses and discussions effectively informed the decision-maker and the public, thus allowing the BLM to take a "hard look" by presenting the environmental impacts of the alternatives in comparative form (quantified greenhouse gas emissions), and discussing cumulative climate impacts.

obtained from each dollar of costs (Field 2008). Since the full social benefits of energy production have not been monetized, quantifying only the costs of GHG emissions but not the benefits would yield information that is both potentially inaccurate and not useful for the decision-maker and the public.

To summarize, cost-benefit analyses and regional economic impact analyses are very different methods that are focused on quantifying/monetizing different measures (social welfare and economic activity respectively) and are based upon differing assumptions and terminology and are not interchangeable. As such, results from a regional economic impact analysis (e.g. jobs or labor income) are not considered benefits or costs (Watson et al. 2007).

Based upon their views and values, people may perceive increased economic activity as a 'positive' impact that they desire to have occur; however, that is very distinct from being an 'economic benefit' as defined in economic theory and methodology (Watson et al. 2007, Kotchen 2011). Additionally, another person may perceive increased economic activity as a 'negative' impact due to potential influx of additional workers and competition for jobs. Therefore, it is critical to distinguish that how people may perceive an economic impact is not the same as, nor should be interpreted as, a cost or a benefit as defined in a cost-benefit analysis.

Though not monetized, climate impacts associated with GHG emissions were analyzed in the Wright Area FEIS. Research indicates that for difficult environmental issues such as climate change, most people more readily understand when the issue is brought to a scale that is relatable to their everyday life (Dietz 2013); the science and technical aspects are presented in an engaging way such as narratives about the potential implications of the climate impacts (Corner, Lewandowsky, Phillips, and Roberts 2015); and the narratives use examples relevant to the audience that link the local and global scales (National Research Council 2010). In order to more effectively convey the potential climate impacts, the BLM qualitatively discussed potential climate change trends at several scales in Section 4.2.14.1 of the Wright Area FEIS. This approach presents the data and information in a manner that follows many of the guidelines for effective climate change communication developed by the National Academy of Sciences (National Research Council 2010), making the information more readily understood by the decision-maker and the general public.

In addition to the qualitative climate change discussion, the BLM quantified GHG emissions in the Wright Area FEIS for the different alternatives, including the No Action Alternative. As noted in the Remand EA, Table 3-24 in the Wright Area FEIS (p. 3-325) indicated that for all six[46] LBA tracts analyzed in the FEIS, the estimated annual CO_2e emissions[47] associated with the mining of that coal (including projected methane emissions vented from exposed, unmined coal) would be 2.5 million metric tonnes (MMmt). Additionally, the Wright Area FEIS further discussed that based upon estimates from the Center for Climate Strategies the 2007 CO_2e

[46]The Wright Area FEIS analyzed six LBA tracts; however, after the FEIS was completed two tracts were withdrawn per company request. Therefore CO2e emissions discussed in the Wright Area FEIS regarding all six LBA tracts likely overestimate potential emissions. The Remand EA provides emissions for the remaining four tracts.

[47]As discussed in the Wright Area FEIS, "[e]missions are measured as metric tons (tonnes) of carbon dioxide equivalents (CO2e). CO2e is a unit of measure that takes into account the global warming potential of each emitted GHG in terms of equivalent CO2 emissions" (p. 3-325).

emissions (1.25 MMmt) from the applicant mines represented 2.22 percent of the 2010 state-wide CO_2e emissions. With the addition of the six LBA tracts analyzed in the Wright Area FEIS, the estimated total CO_2e emissions at the applicant mines would represent 3.61 percent of the projected 2020 state-wide emissions (please see the Wright Area FEIS for more details). Section 4.2.14.2 of the Wright Area FEIS also provided additional detail on the cumulative effects of combustion of coal from the LBA tracts by power plants, including estimating annual CO_2 emissions from the projected upper and lower coal production scenarios included in the Powder River Basin Review analyses (Table 4-37 of Wright Area FEIS), estimated annual CO_2e emissions from mining operations at the specific applicant mines (Table 4-38 of Wright Area FEIS), and estimated annual CO_2 emissions from combustion of coal produced from each specific LBA tract as proposed under the Proposed Action and by Alternative 2 (Table 4-39 of Wright Area FEIS). The Wright Area FEIS also states that the applicant mines produced 228.3 million tons of coal in 2008 and that "[c]ombustion of those 228.3 million tons of coal to produce electricity produced about 378.7 million tonnes of CO_2 emissions, or about 5.4 percent of the total estimated anthropogenic CO_2 emissions produced in the U.S. in 2008" (p. 4-139). The FEIS further states that under the No Action Alternative, CO_2 emissions associated with combustion of the coal produced by the applicant mines "would be extended at about this level for up to approximately 10 years beyond 2008, while the mines recover their remaining estimated 2,483 million tons of currently leased coal reserves" (p. 4-139-141).

The Remand EA also includes an updated and expanded discussion of estimated indirect GHG emissions for the No Action Alternative from the Wright Area FEIS and other scenarios. The Remand EA's discussion of GHGs is included in response to changes in information, methodology, and court ordered direction since the analysis of GHGs was completed for the FEIS. Changes addressed in the Remand EA's discussion include:

- Withdrawal of two LBA tracts (West Hilight and West Jacobs);
- Global warming potentials (GWPs) for the greenhouse gases for two different time horizons;
- Indirect GHG emissions including downstream combustion and transportation; and,
- Direction from the District Court to address BLM's claim in the FEIS that "…it is not likely that selection of the No Action [A]lternative would result in a decrease of U.S. CO_2 emissions attributable to coal mining and coal-burning power plants…"

Remand EA Tables 4.5.1 through 4.5.10 present the results of calculations completed to assess indirect emissions[48] from the No Action Alternative as described in the Wright Area FEIS. In addition, results are presented for the Wright Area FEIS Selected Alternative (Alternative 2 in the FEIS) and the Selected Alternative minus the two LBA tracts that were withdrawn after the FEIS was completed. In addition, estimated emissions based on actual production in 2017 are presented for comparison. These additional scenarios are presented to illustrate the difference in potential emissions between no leasing and leasing and to compare to recent actual emissions (see Remand EA Tables 4.5.1 through 4.5.10 for more information). Additionally the Remand EA discusses the difference in indirect GHG emissions between leasing and not leasing which is

[48] Direct emissions of GHGs from coal mining and coal mining operations are extensively and adequately addressed in the FEIS and represent only a small fraction of total emissions when compared to the indirect emissions, so they are not reanalyzed in the Remand EA. The indirect emissions assessed herein include GHG emissions from the combustion of recovered coal and from the rail transportation of the recovered coal.

approximately 623 MMmt/yr and 7,421 MMmt/yr for the life of the mines. This difference represents approximately 9.6% of total U.S. GHG emissions in 2017. It is important to note that this estimate of the difference in indirect emissions between the Wright Area FEIS No Action Alternative and Selected Alternative scenarios does not take into account other factors that could influence the difference such as economic and regulatory drivers, changes in technology, or availability of replacement energy sources. Therefore, the actual difference in emissions between leasing and not leasing could range from 0 to significantly more than the estimated amounts and BLM cannot make a definitive statement about the degree to which regional or global GHG emissions would be impacted by leasing versus not leasing the proposed LBA tracts.

The Wright Area FEIS and Remand EA discussed climate trends and projections and quantified greenhouse gas emissions in a meaningful and engaging way, connecting the reader and decision-maker to relevant local, regional, and global impacts. Furthermore, the Wright Area FEIS also discussed various potential U.S. actions and strategies that were known at that time to address GHG emissions (see Section 4.2.14.3 of Wright Area FEIS) as well as discussed current and future energy related GHG emissions (see Section 4.2.14.4 of Wright Area FEIS). These additional discussions help to portray the difficulty and uncertainty involved with projecting future GHG emissions from a specific coal leasing action.

Finally, the SCC protocol does not measure the actual incremental impacts of a project on the biophysical environment in a specific location and does not include all damages or benefits from carbon emissions. The SCC protocol estimates economic damages associated with an increase in carbon dioxide emissions - typically expressed as a one metric ton increase in a single year - and includes, but is not limited to, potential changes in net agricultural productivity, human health, and property damages from increased flood risk over hundreds of years. The dollar cost figure arrived at based on the SCC calculation represents the value of damages avoided if, ultimately, there is no increase in carbon emissions. But the dollar cost figure is often generated in a range and provides little benefit in assisting the authorized officer's decision for a specific coal leasing action. Moreover, there are no current criteria or thresholds that determine a level of significance to any monetary value calculated by the SCC protocol.

To summarize, the BLM did not undertake an analysis of SCC because 1) NEPA does not require cost-benefit analysis and the FEIS did not conduct an economic cost-benefit analysis; and, 2) the full social benefits of energy production have not been monetized, and quantifying only the costs of GHG emissions but not the benefits would yield information that is both potentially inaccurate and not useful especially given that there are no current criteria or thresholds that determine a level of significance for SCC monetary values. The approach taken in the Wright Area FEIS and the Remand EA that qualitatively discusses climate projections and the link to GHGs and quantifies GHG emissions for the various alternatives effectively informs the decision-maker and the public of future climate effects at a variety of scales, whereas the social cost of carbon metric would only provide a monetary value at the global scale.

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